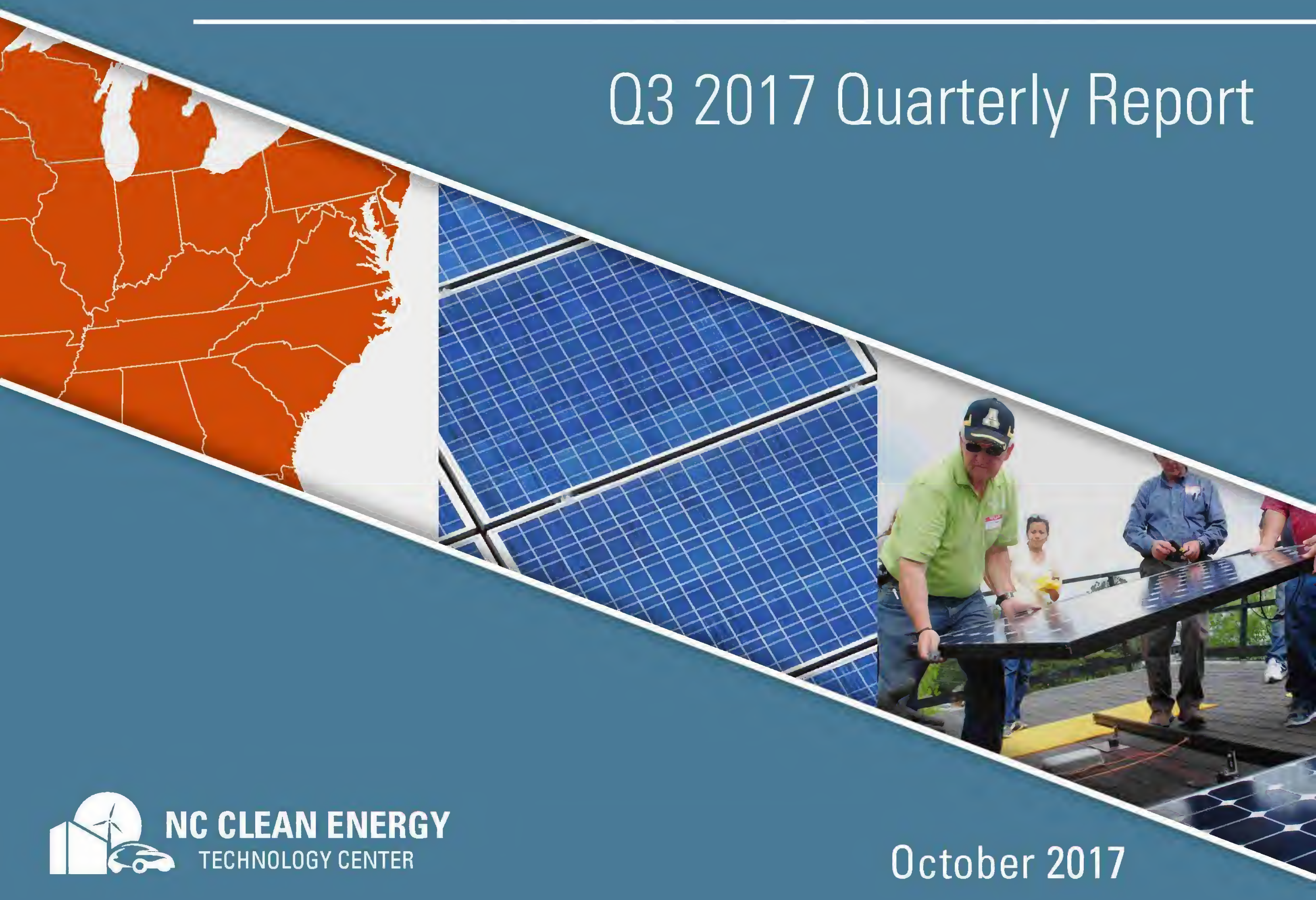
50 States of SOLAR

Q3 2017 Quarterly Report



NC CLEAN ENERGY TECHNOLOGY CENTER

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The NC Clean Energy Technology Center is a UNC System-chartered Public Service Center administered by the College of Engineering at North Carolina State University. Its mission is to advance a sustainable energy economy by educating, demonstrating and providing support for clean energy technologies, practices, and policies. The Center provides service to the businesses and citizens of North Carolina and beyond relating to the development and adoption of clean energy technologies. Through its programs and activities, the Center envisions and seeks to promote the development and use of clean energy in ways that stimulate a sustainable economy while reducing dependence on foreign sources of energy and mitigating the environmental impacts of fossil fuel use.

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PREVIOUS EDITIONS

The 50 States of Solar is a quarterly publication. Previous executive summaries and older full editions of *The 50 States of Solar* are available here:

- Q2 2017 Executive Summary
- Q1 2017 Executive Summary
- Q4 2016 and 2016 Policy Review – Executive Summary
- Q3 2016 Executive Summary
- Q2 2016
- Q1 2016
- Q4 2015 and 2015 Policy Review
- Q3 2015
- Q2 2015
- Q1 2015
- Q4 2014

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GLOSSARY OF ABBREVIATIONS

ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
d/b/a	Doing Business As
DER	Distributed Energy Resources
DG	Distributed Generation
IOU	Investor-Owned Utility
kW	Kilowatt
kWh	Kilowatt-Hour
MW	Megawatt
NEM	Net Energy Metering
PPA	Power Purchase Agreement
PV	Photovoltaics
REC	Renewable Energy Credits
RFP	Request for Proposals
TOU	Time of Use

OVERVIEW

PURPOSE

The purpose of this report is to provide state lawmakers and regulators, electric utilities, the solar industry, and other energy stakeholders with timely, accurate, and unbiased updates on how states are choosing to study, adopt, implement, amend, or discontinue policies associated with distributed solar photovoltaics (PV). This report catalogues proposed and enacted legislative, regulatory policy, and rate design changes affecting the value proposition of distributed solar PV during the most recent quarter, with an emphasis on the residential sector.

The 50 States of Solar provides regular quarterly updates of solar policy developments, keeping stakeholders informed and up to date on a timely basis.

APPROACH

The authors identified relevant policy changes through state utility commission docket searches, legislative bill searches, popular press, and direct communication with stakeholders and regulators in the industry.

Questions Addressed

This report addresses several questions about the changing U.S. solar policy landscape:

- How are (1) state regulatory bodies and legislatures and (2) electric utilities addressing fast growing markets for distributed solar PV?
- What changes to traditional rate design features and net metering policies are being proposed, approved, and implemented?
- Where are distributed solar markets potentially affected by policy or regulatory decisions on community solar, third-party solar ownership, and utility-led residential rooftop solar programs?

Actions Included

This report focuses on cataloguing and describing important proposed and adopted policy changes affecting solar customer-generators of investor-owned utilities (IOUs) and large publicly-owned or nonprofit utilities (i.e., those serving at least 100,000 customers). Specifically, actions tracked in this issue include:

- Significant changes to state or utility **net metering** laws and rules, including aggregate caps, system size limits, aggregate net metering rules, and compensation rates for net excess generation
- Changes to statewide **community solar** laws and rules, and individual utility-sponsored community solar programs arising from statewide legislation
- Legislative or regulatory-led efforts to study the **value of solar**, **net metering**, or **distributed solar generation policy**, e.g., through a regulatory docket or a cost-benefit analysis
- Utility-initiated rate requests for **charges applicable only to residential customers with solar PV** or other types of distributed generation, such as added monthly fixed charges, demand charges, stand-by charges, or interconnection fees
- Utility-initiated rate requests that propose a 10% or larger increase in either **fixed charges** or **minimum bills** for all residential customers
- Changes to the legality of **third-party solar ownership**, including solar leasing and solar third-party solar power purchase agreements (PPAs), and proposed **utility-led rooftop solar** programs

In general, this report considers an "action" to be a relevant (1) legislative bill that has been passed by at least one chamber or (2) a regulatory docket, utility rate case, or rulemaking proceeding. Introduced legislation related to third-party sales is included irrespective of whether it has passed at least one chamber, as only a small number of bills related to this policy have been introduced. Introduced legislation pertaining to a regulatory proceeding covered in this report is also included irrespective of whether it has passed at least one chamber.

Actions Excluded

In addition to excluding most legislation that has been introduced but not advanced, this report excludes a review of state actions pertaining to solar incentives, as well as more general utility cost recovery and rate design changes, such as decoupling or time-of-use tariffs. General changes in state implementation of the Public Utility Regulatory Policies Act of 1978 and subsequent amendments, including changes to the terms of standard contracts for Qualifying Facilities or avoided cost rate calculations, are also excluded unless specifically related to the policies described above. The report also does not cover changes to a number of other policies that affect distributed solar, including solar access laws, interconnection rules, and renewable portfolio standards. Details and updates on these and other policies and incentives are available at www.dsireusa.org.

U.S. DISTRIBUTED SOLAR MARKET

For the U.S. solar market, 2016 was a record year with nearly 14.8 Gigawatts of capacity being added.[1] While this was a major milestone for the solar industry as a whole, the residential sector experienced slowed growth in 2016, largely due to greater difficulty acquiring customers in established markets.[2] However, GTM analysts note that state policy, particularly the outcome of major net metering and rate design proceedings, will be a key determinant in long term growth rates in both mature and emerging residential solar markets.[3] While residential markets experienced slowed growth in 2016, community solar and virtually net metered solar had a banner year, with four times as much community solar capacity being added as in 2015.[4]

Increased Attention to State Solar Policies

State and utility solar policies are undergoing review in nearly every state in the country, with 47 states and DC considering changes in 2016. According to Utility Dive's 2017 State of the Electric Utility survey, only 6% of utility respondents felt that distributed resource policy, including net metering, is not important at all, and 65% of respondents noted that these policies are important or very important today.[5] Another 60% responded that rate design reform is important or very important today.[6]

This increased attention to solar policy and rate design comes in response to a fundamental shift occurring in the U.S. electric system. The electric system in the U.S. has traditionally been a "one-way street", with power flowing from utility-owned centralized generation, via utility-owned transmission and distribution lines, toward end-use customers. However, the electric system is increasingly becoming more of an interconnected web, with small but growing numbers of end-use customers also generating electricity with small-scale, distributed systems that are capable of providing various services to the grid. Because state policies and utility rate designs were developed around the former, it is likely that significant changes will be necessary to ensure fair market access and compensation for grid participants.

Fair compensation for both solar customers and utilities is at the heart of ongoing state solar policy and rate design discussions. The question of potential cost shifts resulting from net metering is becoming more important with increasing levels of distributed generation on the grid. Utilities frequently recover a large portion of their fixed operating costs through residential customers' variable rates, and suggest that because net-metered customers are significantly reducing this variable portion of their bills, they are not paying for their fair share of fixed operating costs. However, many also suggest that solar customers provide benefits to the grid and other ratepayers that they are not directly compensated for. This dynamic has led many states to formally study the costs and benefits of net metering or the value of distributed generation to the grid in order to help identify the appropriate level of compensation for solar customers.

OVERVIEW OF Q3 2017 POLICY CHANGES

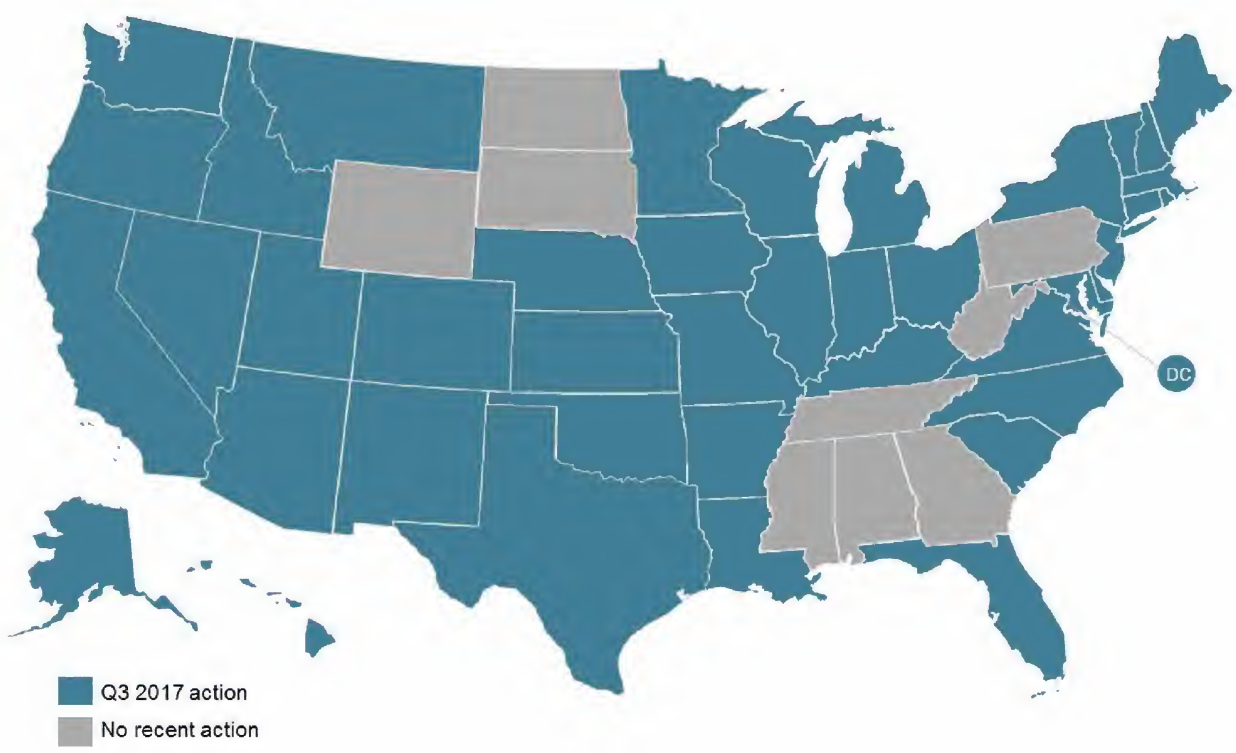
Table 1 provides a summary of state actions related to DG compensation, rate design, and solar ownership during Q3 2017. Of the 142 actions catalogued, the most common were related to residential fixed charge and minimum bill increases (44), followed by DG compensation rules (36), and DG valuation or net metering studies (23). The actions occurred across 41 states plus DC in Q3 2017 (Figure 1). Box 1 highlights some of the key actions of Q3 2017, described in greater detail in the following sections.

Table 1. Summary of Policy Actions (Q3 2017)

Policy Type	# of Actions	% by Type	# of States
Residential fixed charge or minimum bill increase	44	31%	26 + DC
DG compensation rules	36	25%	24
DG valuation or net metering study	23	16%	19 + DC
Community solar	18	13%	13
Residential demand or solar charge	14	10%	7
Utility-led rooftop PV programs	5	4%	5
Third-party ownership of solar	2	1%	1
Total	**142**	**100%**	**41 States + DC**

Note: The "# of States/ Districts" total is not the sum of the rows, as some states have multiple actions. Percentages are rounded and may not add up to 100%.

Figure 1. Action on Net Metering, Rate Design, & Solar Ownership Policies (Q3 2017)



Box 1. Top Five State Solar Policy Developments of Q3 2017

NV Energy Submits Proposal to Implement A.B. 405 Net Metering Changes

After terminating net metering in 2015, the Nevada Legislature restored it with A.B. 405, which the Governor signed in June 2017. The Public Utilities Commission of Nevada held expedited proceedings to implement the policy changes. In its July filing, NV Energy presented tariffs that represented net billing, rather than net metering, and proposed an increase the fixed charge for all residential customers. In a September decision, the Commission rejected NV Energy's tariffs, arguing that the plain language of A.B. 405 requires a return to traditional net metering, which utilizes a monthly netting period.

Utah Begins Transition Away From Net Metering

In September 2017, the Utah Public Service Commission approved a settlement agreement ending retail rate net metering for new DG customers starting November 15th. A transition program with a reduced export credit rate will begin for new DG customers at this time, until a more permanent export credit rate is determined through an in-depth proceeding. The export credit proceeding is expected to conclude within three years.

Kansas Corporation Commission Makes DG Policy Determination

The Kansas Corporation Commission approved a settlement in September 2017, making a general determination that residential DG customer rates should be cost-based and not include any unquantifiable benefits. The Commission also noted that it is appropriate to create a separate customer class for DG customers and apply demand or DG capacity-based charges. However, any changes to tariffs will take place in utility-specific filings.

Idaho Power Requests a Separate Customer Class for DG Customers

In July 2017, Idaho Power filed a proposal to separate new residential and general service customers with on-site generation into unique customer classes. Idaho Power did not propose any rate changes for these customers at this time, but the utility requested that a generic docket be opened to develop a new compensation structure for customer-sited DERs. Idaho is one of five states without statewide net metering or other DER compensation rules.

Illinois Begins Implementation of Community Solar Program

Pursuant to the Future Energy Jobs Act, the Illinois Power Agency published a draft version of its Long-Term Renewable Resources Procurement plan in September 2017, while utilities filed proposed community net metering tariffs. The new tariffs compensate participants at the retail electric supply rate, but do not include transmission and distribution components. The draft plan includes funding for a low-income community solar incentive program and a competitive bidding program for low-income community solar pilot projects.

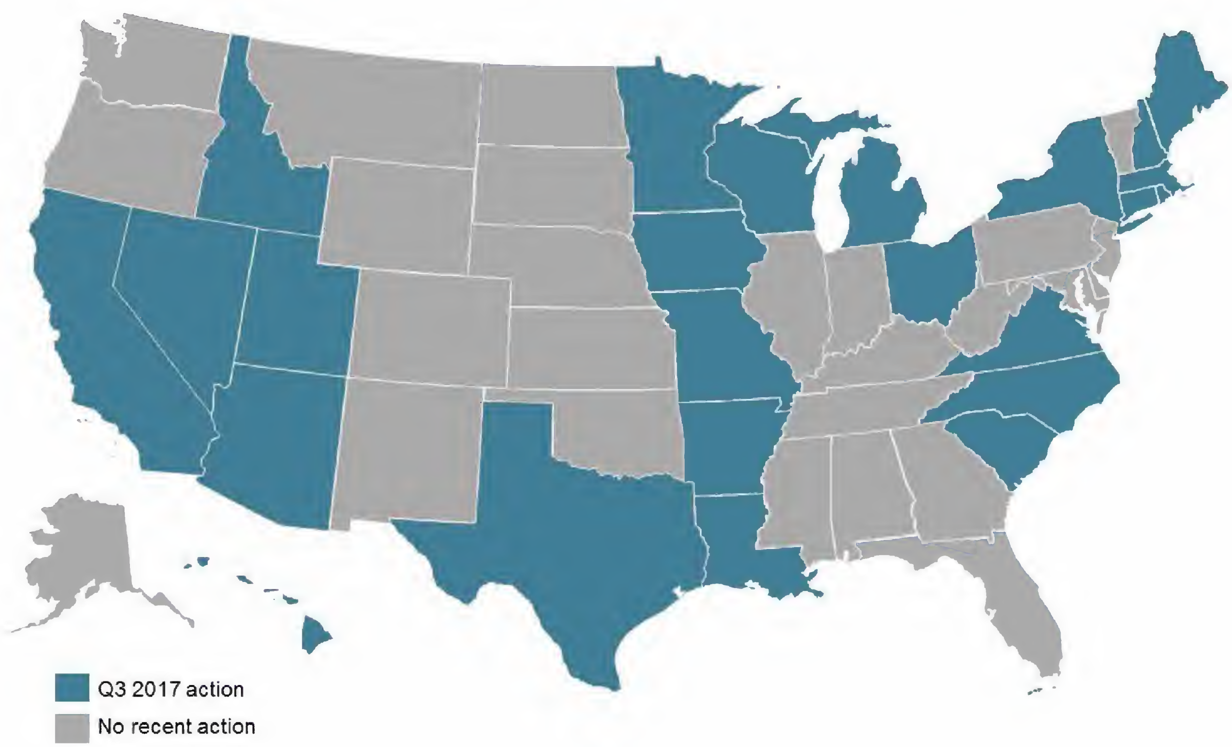
DG COMPENSATION POLICY CHANGES

Key Takeaways:

- In Q3 2017, there were 36 actions ongoing or under consideration in 24 states related to DG compensation policy changes.
- Seventeen states took action related to the development of a net metering successor tariff or adjusting credit rates for excess generation.
- Utah became the ninth state to adopt a net metering successor tariff, closing retail rate net metering to new customer-generators beginning November 15th.

In Q3 2017, there were 36 actions ongoing or under consideration in 24 states related to distributed generation (DG) compensation policies. Of these, seventeen states considered changes related to credit rates for excess generation or the development of a net metering successor tariff.

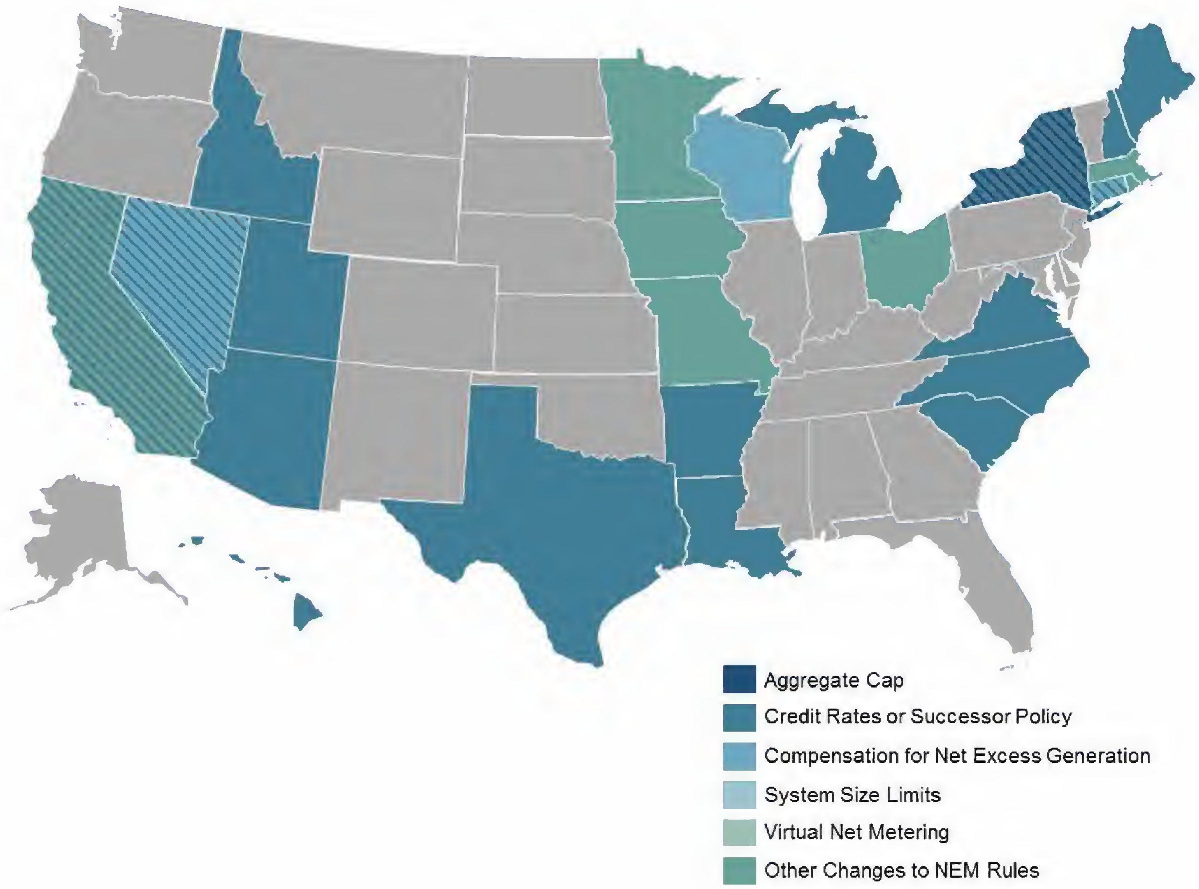
Figure 2. Action on DG Compensation Policies (Q3 2017)



In Q3 2017, Utah became the latest state to adopt a net metering successor tariff. Beginning November 15th, new Rocky Mountain Power customer-generators will be placed on an interim net metering tariff, which takes the form of net billing, with an export compensation rate of 9.2 cents per kWh. The Commission will initiate a separate export credit proceeding to determine a longer-term compensation rate.

Several states – including Arkansas, California, Hawaii, Louisiana, New Hampshire, and now Utah – have recently made incremental changes to net metering policies while broader and more forward-looking reforms are considered. The Michigan Public Service Commission recently opted to continue net metering as it currently stands until a successor is approved, while decisions in both Arizona and Maine take a phased approach to credit rate reduction.

Figure 3. Proposed and Adopted Changes to DG Compensation Policies by Type of Change (Q3 2017)

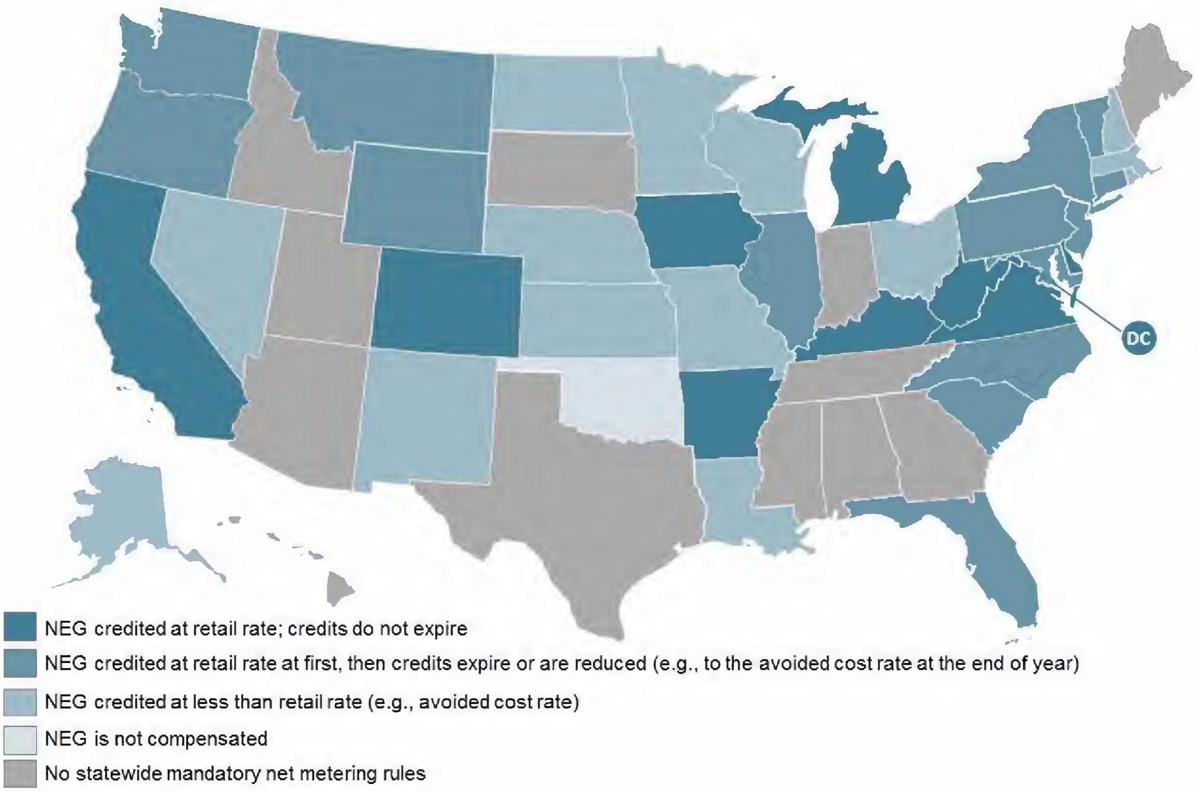


While Utah began its transition away from net metering this quarter, the Public Utilities Commission of Nevada approved rules reverting back to retail rate net metering. The netting period and definition of "excess generation" became an issue (see Box 3 for more on this topic), with the Commission ultimately approving traditional net metering, which utilizes a monthly netting period. Any excess generation remaining at the end of the month will be credited at a reduced rate. Other states, including Louisiana and New Hampshire, recently reduced compensation rates for monthly net excess generation as well, and are currently considering broader net metering changes.

Another emerging issue related to compensation for DG customers is whether these customers should be separated into a unique customer class or served under the same rates applicable to general residential or commercial customers. Two utilities – Idaho Power (ID) and Interstate

Power & Light (IA) – recently filed proposals to separate DG customers into a new customer class. Notably, neither proposal includes any changes to the actual rates for these customers at this time.

Figure 4. Compensation for Net Excess Generation Under Net Metering



Rocky Mountain Power (RMP) in Utah also requested the creation of a new customer class for DG customers in late 2016, but RMP's proposal did include significant rate changes for these customers, including reduced variable charges, an increased fixed charge, and a new demand charge. As noted previously, the Utah Public Service Commission approved a net metering successor tariff for RMP in Q3 2017, which does not create a new customer class for DG customers.

Kansas and Montana have also seen the issue of customer class come up, with Montana's H.B. 219 opening the door to the creation of a separate rate class for customer-generators. In Kansas, regulators determined that it is appropriate to create a separate rate class for DG customers and apply demand or capacity-based charges; however, any customer class and rate changes will take place in individual utility filings.

An issue gaining increased attention in Q3 2017 was net metering eligibility for solar-plus-storage systems. Following requests for advisory rulings from both Tesla and Genbright, the Massachusetts Department of Public Utilities initiated in inquiry into the net metering eligibility of solar-plus-storage in early October 2017. The inquiry also addresses forward capacity market

eligibility of net-metered capacity. New York and Rhode Island are addressing net metering eligibility and compensation for solar-plus-storage facilities as well.

Table 2. 2017 Bills Enacted Related to DG Compensation (As of 10/4/17)

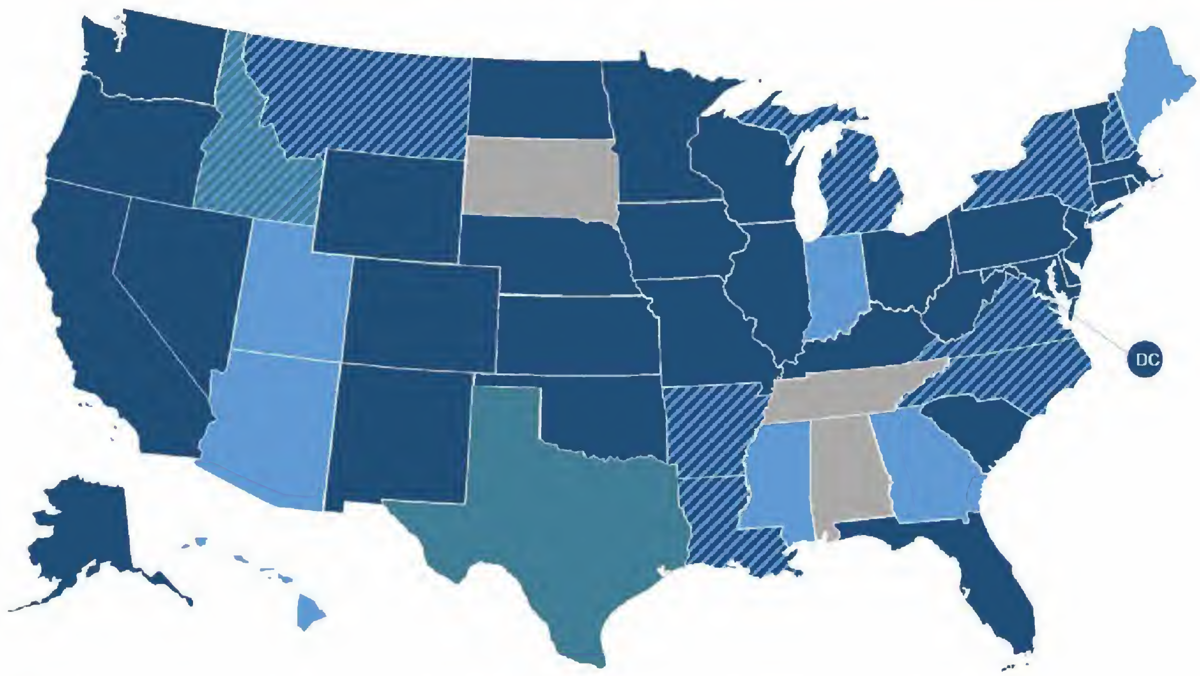
State	Bill #	Topics
Indiana	S.B. 309	Credit Rates, Grandfathering
Montana	H.B. 219	Credit Rates, Grandfathering, Study
Nevada	A.B. 405	Credit Rates, Study
New Hampshire	S.B. 129	Virtual Net Metering
North Carolina	H.B. 589	Credit Rates, Fees, Grandfathering, Study
Rhode Island	H.B. 5318	Study
	S.B. 880	Study
Vermont	H.B. 411	Credit Rates
Virginia	H.B. 2303	Credit Rates, System Size
	S.B. 1394	Credit Rates, System Size

Most states concluded their 2017 legislative sessions during Q2 or Q3 2017. While at least 75 bills relating to DG compensation were introduced, only ten were enacted as of early October 2017. The most common topic of enacted bills was the credit rate for excess generation, with seven bills addressing this. Five bills initiated studies related to DG compensation or the costs and benefits of net metering. As a result of the 2017 legislative session, two states (Indiana and Nevada) have adopted new DG compensation policies, while another two states (Montana and North Carolina) will consider changes following the conclusion of net metering cost-benefit studies.

Box 2. A Note on Net Metering Terminology

Credit rates refers to changes to compensation for all electricity exported to the grid, either instantaneously or netted over a period shorter than the billing period (e.g., 15-minute or 60-minute intervals.) **Net excess generation** includes changes to how utilities compensate customers for excess production at the end of a billing period after a one-to-one netting of production and consumption has occurred. An **aggregate cap** refers to the maximum limit for net-metered capacity allowed to participate in a state's or a utility's net metering program, whereas the **system size limits** are capacity limits for individual systems to net meter. **Aggregate net metering** refers to a program design allowing one or more customers to aggregate multiple electric meters for the purpose of allocating net metering credits. **Virtual net metering** is a type of aggregate net metering where credits from one solar PV system are used to offset multiple customers' electricity bills. **Meter aggregation** is another type of aggregate net metering in which a single customer may offset electrical use from multiple meters on his or her property. **REC ownership** refers to rules that specify whether renewable energy certificates/credits generated by a net-metered system accrue to the solar PV system owner or the utility. **Net metering rules** encompass other policy changes to net metering not covered by any of these other categories.

Figure 5. Current Net Metering and Distributed Generation Compensation Policies



Alternative DG compensation rules under consideration

No statewide distributed generation compensation rules

Statewide distributed generation compensation rules other than net metering

No statewide mandatory net metering rules, but some utilities offer net metering

State-developed mandatory net metering rules for certain utilities

Box 3: Net Metering and Net Billing Terminology

Terminology for distributed generation compensation systems can be confusing, and with a large number of recent and proposed policy changes, the potential for confusion is especially high right now. One point of confusion is the distinction between net metering and net billing. These terms are often used interchangeably by governments and utilities,[*] but the two systems have important differences. After reviewing the definitions of these terms used in the academic literature,[†] we have devised definitions for net metering and net billing. These definitions should help to standardize the use of these terms and add clarity to the distributed generation policy discussion.

Net Metering is a billing mechanism that compensates a customer for excess generation from an on-site energy system through credits that offset electricity usage at other times during the billing period. Electricity generated on-site first supplies the customer's real-time use of electricity. Any electricity generated on-site in excess of the amount used in real time is exported to the grid. Under net metering, this excess generation is used to offset the customer's usage at other times during the billing period; credits for exported energy are deducted from the amount of electricity purchased from the utility during the billing period, in effect moving the customer's electricity meter backward. This means that customers are compensated at the retail rate for electricity exported to the grid, at least as long as total on-site generation during the billing period is less than the customer's total electricity usage during the billing period. When generation exceeds total usage during the billing period, different crediting schemes may be used.

Net Billing is a billing mechanism that compensates a customer for excess generation from an on-site energy system by payment of a separate rate for electricity generated in excess of real-time use (or excess remaining after netting production and consumption over intervals shorter than the billing period – e.g., 15-minute or 60-minute intervals.) Electricity generated on-site first supplies the customer's real-time electricity use. Any electricity generated on-site in excess of the amount used in real time is exported to the grid. Under net billing, the utility pays the customer for this excess generation at a separate rate rather than crediting the generation against usage at other times in the billing period. Under net billing, a customer's meter is essentially "stopped" when on-site generation is meeting real-time demand, but unlike with net metering, it does not go "backward". The rate of compensation for exported electricity under net billing varies by state and utility. It is usually lower than the retail rate, but is often higher than the monthly average rates paid in the wholesale electricity market. Effectively, net billing customers still receive the retail rate for on-site generation that supplies their electricity usage in real time because it displaces grid-supplied electricity they would otherwise have to purchase at the full retail rate.

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[*] For example, Mississippi calls its new system "Net Metering" even though it more closely resembles net billing.

[†] Hughes, L. & Bell, J., 2006; Yamamoto, Y., 2012; Dufo-Lopez, R. & Bernal-Agustin, J., 2015.

Table 3. Updates on DG Compensation Policies (Q3 2017)

State	Type of Change	Description	Source
AR	Credit Rates, Net Metering Rules	In April 2016, the Arkansas Public Service Commission (PSC) opened a docket, pursuant to Act 827 of 2015, to ensure net metering rates, terms, and conditions are appropriate to recover the full utility costs to serve net metering customers, net of any quantifiable benefits. The proceeding was also initiated to investigate guidelines for approving non-residential net metering facilities over 300 kW. In August 2016, the PSC approved a unanimous proposal to bifurcate and establish a separate procedural schedule for issues relating to rates, terms, and conditions for net metering ("rate issues"). The PSC also approved a proposal to establish a Net Metering Working Group to address these rate issues. In March 2017, the PSC completed Phase I of the proceeding, and in June 2017, the Net Metering Working Group submitted a progress report. In September 2017, the Working Group submitted its final joint report and recommendations. As two schools of thought exist within the working group, two sub-groups were formed and provided separate recommendations within the report. Sub-Group 1 consists of multiple solar advocacy organizations, environmental groups, and individuals, while Sub-Group 2 consists of many utilities, the Attorney General, the PSC staff, and Arkansas Electric Energy Consumers. Sub-Group 1 recommended that the current net metering credit structure be continued until a complete study of the costs and benefits of net metering has been conducted. Sub-Group 2 recommended a move to net billing (also called "2-channel billing"), crediting excess generation at an embedded cost-of-service rate rather than the retail rate. A hearing will be held on November 30th.	Docket No. 16-027-R Joint Report and Recommendations of the Net-Metering Working Group
AZ	Credit Rates	Arizona Public Service (APS) filed a general rate case in June 2016 that includes changes to its net metering tariff. APS' proposed net metering rider does not allow for one-to-one offsetting of generation and consumption over the billing period. Instead, any exported energy would be credited at $0.0292/kWh during the summer and $0.02867/kWh during the winter. The proposed changes allow for a 20-year grandfathering period for existing net metering customers. In December 2016, the Arizona Corporation Commission (ACC) voted in the value of DG docket (Docket No. E-00000J-14-0023) to end retail rate net metering and instead credit new solar customers at an avoided cost rate for energy sent to the grid. In March 2017, a settlement agreement was	Docket No. E-01345A-16-0036 Settlement Agreement Decision No. 76295

	filed, which includes the rate at which new customer-generators will be initially be credited at, should the agreement be approved. The settlement the Resource Comparison Proxy Rate for exported energy in year one to be $0.129/kWh. In May, the ACC staff filed a brief concluding that the settlement should be adopted, and the ACC approved the agreement in August 2017.	
Credit Rates	Tucson Electric Power (TEP) filed a general rate case in November 2015 that included changes to its net metering tariff. TEP's proposed net metering rider would not have allowed for one-to-one offsetting of generation and consumption over the billing period. Instead, any exported energy would be credited at a utility-scale renewable energy purchase rate. In December 2016, the Arizona Corporation Commission (ACC) voted in the value of DG docket (Docket No. E-00000J-14-0023) to end retail rate net metering in the state and instead credit new DG customers at an avoided cost rate for energy exported to the grid. This rate is currently being decided within each utility's active rate case. TEP and UNS Electric proposed a single DG export rate for both companies of 9.73 cents/kWh. The ACC staff recommended separate DG export rates for TEP and UNS, with an initial rate of 10.5 cents/kWh for TEP. Vote Solar and the Energy Freedom Coalition of Americas (EFCA) also recommended separate export rates for TEP and UNS, with Vote Solar recommending a rate of 15.4 cents/kWh for TEP and EFCA recommending a rate of 15.37 cents/kWh for TEP. In August 2017, TEP filed its Phase 2 (DG export rate and DG rate design issues) rebuttal testimony, maintaining its proposal for an initial export rate of 9.73 cents/kWh, which would then decline to 8.76 cents/kWh. TEP has also proposed mandatory time-of-use rates for DG customers, with one tariff including a grid access charge based on DG system size and one tariff including a demand charge. A hearing on Phase 2 issues is scheduled for October 23rd.	Docket No. E-01933A-15-0322
Credit Rates	UNS Electric filed a general rate case in May 2015 that included changes to its net metering tariff. UNS' proposed net metering rider would not have allowed for one-to-one offsetting of generation and consumption over the billing period. Instead, any exported energy would be credited at a utility-scale renewable energy purchase rate. The Arizona Corporation Commission (ACC) issued a decision in UNS' rate case in August 2016, but left the net metering and DG customer rate design portions of the	Docket No. E-04204A-15-0142

		docket open in order to utilize the filings and conclusions in the ongoing Value of DG docket (Docket No. E-00000J-14-0023). In December 2016, the ACC voted in the Value of DG proceeding to end retail rate net metering and instead credit new solar customers at an avoided cost rate for energy sent to the grid. This rate is currently being decided within each utility's active rate case. UNS Electric and TEP proposed a single DG export rate for both companies of 9.73 cents/kWh. The ACC staff recommended separate DG export rates for UNS and TEP, with an initial rate of 12.8 cents/kWh for UNS. Vote Solar and the Energy Freedom Coalition of Americas (EFCA) also recommended separate export rates for UNS and TEP, with Vote Solar recommending a rate of 15.2 cents/kWh for UNS and EFCA recommending a rate of 18.23 cents/kWh for UNS. In August 2017, UNS filed its Phase 2 (DG export rate and DG rate design issues) rebuttal testimony, maintaining its proposal for an initial export rate of 9.73 cents/kWh, which would then decline to 8.76 cents/kWh. UNS has also proposed mandatory time-of-use rates for DG customers, with one tariff including a grid access charge based on DG system size and one tariff including a demand charge. A hearing on Phase 2 issues is scheduled for October 23rd.	
CA	Aggregate Cap	Alameda Municipal Power reached its aggregate cap on net metering in May 2017. Systems interconnecting by July 31, 2017 will be grandfathered into net metering. Systems interconnected after that date will be placed on Alameda Municipal Power's Eligible Renewable Generation plan.	Alameda Municipal Power Website
	Credit Rates, Net Metering Rules	A January 2016 decision from the California Public Utilities Commission established a successor tariff to replace net metering when the utilities reach their aggregate caps. In May 2017, a number of parties, including the Solar Energy Industries Association, filed a petition for modification, asking that multifamily affordable housing properties participating in virtual net metering be exempt from the mandatory time-of-use tariff requirement. The ALJ issued a ruling in August 2017, requiring the utilities to examine the potential rate impacts of various time-of-use rate scenarios on virtual net metering customers. The utilities provided their responses in mid-September, and various parties jointly requested additional data from the utilities to better analyze the impacts.	Docket No. R14-07-002

	Credit Rates, Net Metering Rules	Pursuant to the California Public Utilities Commission's (CPUC) January 2016 net metering successor tariff decision, customers beginning to net meter after each utility's aggregate cap is reached will be required to take service under time-of-use (TOU) rates. San Diego Gas and Electric (SDG&E) reached its aggregate cap in June 2016, and in August 2017, the CPUC issued an order on SDG&E's TOU rate periods. The CPUC approved a shift in the peak period from the current 11am to 6pm to SDG&E's proposed 4pm to 9pm. The new TOU periods become effective December 1, 2017.	Docket No. 15-04-012 Decision No. 17-08-030
CT	Net Excess Generation	The Connecticut Public Utilities Regulatory Authority (PURA) is reviewing the state's net metering credit banking policy, including when and how generated kWhs are accrued, banked, used, priced, and reimbursed, particularly when customers move from supplier to supplier. In November 2016, PURA published its interim final decision, providing that United Illuminating would no longer cash out banked kWhs when a customer switches electric suppliers. The electric supplier at the end of the annual net metering banking period will be responsible for reimbursement paid to the customer for banked kWhs at the wholesale rate. Suppliers are not obligated to serve net metering customers, and customers are able to choose between two annual banking periods – April 1st and October 1st. The interim final decision is not the final decision; PURA will consider parties' responses before reaching a final decision. PURA also directed the utilities to conduct a working group to develop joint recommendations on several issues.	Docket No. 15-09-03
	Credit Rates, Net Metering Rules	In July 2017, the Connecticut Department of Energy and Environmental Protection (DEEP) released its draft version of the 2017 Comprehensive Energy Strategy report. The report recommends replacing net metering with "renewable energy tariffs" to increase equity and transparency. These tariffs would provide system owners with a fixed per-kWh rate for production over a set contract term. This recommendation requires legislative action and a subsequent proceeding through the Public Utility Regulatory Authority to be implemented. DEEP is currently accepting comments on the draft version of its report.	DEEP Draft Comprehensive Energy Strategy
HI	Credit Rates, Net Metering Rules	The Hawaii Public Utilities Commission is investigating the technical, economic, and policy issues associated with distributed energy in two phases. Phase 1 resulted in the transition from traditional net metering to new interim tariff options. Phase 2 was launched by the Commission in	Docket No. 2014-0192 Stipulation for Proposed Revisions to Rule No. 22

		December 2016, stating that work on all Phase 2 issues will be pursued in parallel. Phase 2 of the proceeding also includes a technical track with two issues: (1) how utility DER integration analyses can be improved to more accurately characterize grid capacity from various DERs and (2) how interconnection standards can be modified to promote the safe and smooth integration of increasing levels of DERs onto the grid. In addition to the technical track issues, there are five market track issues that Phase 2 will examine: (1) a longer-term competitive market structure for DER exports and services, including the development of a successor tariff to replace the interim tariffs, (2) alternative rate designs to facilitate safe and beneficial DER integration, (3) expansion of DER options to customer not able to participate directly, including low-income customers, (4) utility participation in DER markets, and (5) mechanisms to facilitate the secure flow of market data between utilities and third parties (including customers). A July 2017 Commission order established the procedural schedule, which involves multiple working groups. In accordance with the schedule, the parties submitted stipulations addressing the Technical Track issues and the Market Track issues in August 2017. One of the stipulations detailed the basic principles of an interim smart export tariff, though parties could not reach agreement on it. Q3 2017 also saw initial statements from individual parties, information requests, and final statements filed through mid-September 2017. A hearing is set for October, with a Commission decision expected to follow.	Decision No. 34534
IA	Customer Class	In April 2017, as part of its general rate case, Interstate Power and Light d/b/a Alliant Energy proposed the separation of DG customers into a unique customer class. The new rate class would not result in rate changes at this time. A hearing was held in October 2017, and initial briefs are due by October 25th.	Docket No. RPU-2017-0001
ID	Credit Rates, Customer Class, Net Metering Rules	In July 2017, Idaho Power proposed changes to its net metering program. Idaho Power's proposal would not make any credit rate changes at this time, but would create two new customer classes for new residential and small general service customers with on-site generation. Customers beginning net metering by December 31, 2017 would be grandfathered under the current net metering rules. Idaho Power also requested that a generic docket be opened at the conclusion of this case to establish a compensation structure for customer-owned DERs that reflects the benefits and costs that DERs bring to the system. The	Docket No. IPC-E-17-13

		proposal would also require new customer-owned generators to install smart inverters. This would take effect within 60 days of the Institute of Electrical and Electronic Engineers (IEEE) adopting an industry standard definition of a smart inverter. A hearing is scheduled for March 2018.	
LA	Aggregate Cap, Credit Rates, Net Excess Generation, Net Metering Rules, Virtual Net Metering	In December 2015, the Louisiana Public Service Commission (PSC) initiated a two-phase rulemaking proceeding to I) modify the state's current net metering rule once a utility reaches the net metering aggregate cap, and II) examine appropriate changes to solar policies in Louisiana. In December 2016, the PSC adopted the staff's recommendation filed in April 2016, reducing the credit rate for net excess generation from retail to avoided cost. Parties filed initial Phase II comments in February 2017. Entergy Louisiana, SWEPCO, Cleco, and the Association of Louisiana Electric Cooperatives all proposed moving from retail rate net metering to "2-channel billing", or "net billing", with all excess generation being credited at the avoided cost rate. Entergy and SWEPCO acknowledged that time-varying rates are another option to examine, although they would potentially propose an increased fixed charge or a demand charge to accompany these rates, and they noted there are additional metering costs involved. SWEPCO also proposed reducing the residential system size limit from 25 kW to 10 kW to prevent oversized systems and is supportive of establishing a new aggregate cap. Cleco suggested the PSC could set system size limits based on an average usage study. The Alliance for Affordable Energy proposed maintaining retail rate net metering and considering an increase to the aggregate cap, as well as time-varying or location-based credit rates. The Alliance also suggested consideration of community solar or aggregation options. The Sierra Club also supports maintaining retail rate net metering, but re-evaluating the basis for the current aggregate cap and clarifying that existing customers are grandfathered under current rules. The Sierra Club proposed consideration of a moderate minimum bill to ensure fixed cost recovery. Solar leasing and efficiency services company Posigen proposed that an independent consultant specializing in clean energy deployment and IT infrastructure be hired to analyze demand-side management resources, including residential solar, before any changes be made to net metering. No docketed activity occurred during Q2 or Q3 2017.	Docket No. R-33929
MA	Net Metering Rules	Legislation enacted in April 2016 authorized the Department of Public Utilities (DPU) to approve a Minimum Monthly Reliability Contribution (MMRC) for net metering customers after the aggregate capacity	Chapter 75 of the Acts of 2016 Docket No. 16-64

	of installed solar generating facilities in the state reaches 1,600 MW ("MMRC date"). In January 2017, the DPU published an order, outlining what the scope of an MMRC proposal should include, should the distribution utilities choose to file proposals. The stakeholders did not reach consensus on an MMRC proposal, and the DPU declined to convene another stakeholder meeting. The DPU also declined to make a finding regarding the MMRC date, as there are multiple interpretations as to what constitutes "capacity of installed solar generating facilities." In June 2017, the DPU reopened the MMRC proceeding for the limited purpose of determining this MMRC date, as one utility (Eversource) has a pending proposal for an MMRC. In September 2017, the DPU issued an order establishing the MMRC date as May 1, 2017.	June 2017 Order September 2017 Order
Net Metering Rules	In January 2017, the Department of Energy Resources (DOER) released its final program design for the solar incentive program that will succeed the SREC II Program. The new program, called Solar Massachusetts Renewable Target (SMART), is a 1,600 MW declining block program. Small projects will receive a 10-year fixed price term, and large projects will receive a 20-year fixed price term. The maximum eligible project size is 5 MW. Base incentive rates vary by project size, and the incentive structure is different for sized-to-load and standalone projects. Incentive adders for location ($0.02 - building mounted, $0.03 - brownfield, $0.04 - landfill, $0.06 - solar canopy or agricultural), community solar ($0.05), low-income ($0.03 - low income property owners, $0.06 - low income community solar), public ($0.02), and energy storage (variable, based on ratio of storage capacity to solar capacity, as well as storage duration) will also be available. A "subtractor" is also included for projects sited on greenfields. The initial rates will be set through a competitive procurement process for systems larger than 1 MW. Capacity based rate factor indices will be used to set rates for projects 1 MW and smaller. Rates and adders will decrease by 4% per capacity block. The proposal also creates a new compensation option for incentive recipients in addition to net metering and a buy-all, sell-all arrangement. This new on-bill crediting option would offer a single rate for all facilities, allow transfer of credits to off-takers without net metering, and would not have an aggregate cap or public entity system size cap. The proposal notes that the compensation rate for exported energy would likely be set at the basic service rate and that this crediting option would be established via a Department of Public Utilities process. DOER filed an emergency regulation to implement the program in June 2017	DOER Next Solar Incentive Landing Page 225 CMR 20.00

	and held three public hearings in July. In August 2017, DOER filed the final version of the regulation, which removes caps on individual adder categories and increases the cap for the initial auction rate to $0.17/kWh.	
Net Metering Rules	In May 2017, Tesla filed a petition for emergency declaratory relief or an advisory ruling on the eligibility of solar-plus-systems for net metering. Specifically, Tesla requested clarification for solar systems that are paired with battery storage systems, where the battery does not export energy to the grid and is only charged with solar energy. The Department of Public Utilities (DPU) published an order in September 2017, issuing an advisory ruling that the general net metering eligibility of solar-plus-storage systems requires further investigation, but in the interim, these systems should be eligible to net meter. The DPU notes that further investigation could change its opinion on the issue.	Docket No. 17-105 DPU Order
Net Metering Rules	In March 2017, the Department of Public Utilities (DPU) opened an inquiry into the current standards and procedures for seeking exceptions to net metering regulations, specifically relating to Single Parcel Rule that requires net metering systems to be associated with a single parcel of land and interconnected at a single point, behind a single meter, as well as the Subdivision Rule, which requires customers seeking to net meter on a parcel of land subdivided after January 1, 2010 to file a petition with the DPU demonstrating that the subdivision was not created for the purpose of creating multiple parcels to support multiple net metering facilities. The DPU is accepting comments on possible blanket exceptions to these two rules. A technical conference was held in May 2017, and written comments were accepted through July 25th.	Docket No. 17-22
Net Metering Rules	In July 2016, Genbright LLC requested a declaratory ruling as to whether National Grid was acting in a commercially reasonable manner in obtaining payments for capacity of net-metered solar facilities. In November 2016, Genbright amended its petition to also request a declaratory ruling that battery storage systems are not subject to net metering rules. The Department of Public Utilities issued an order in September 2017, determining that the stakeholder interest and complexity surrounding these issues warrants a separate inquiry, initiated by the Department. The Department suspended Genbright's petition until the inquiry is complete.	Docket No. 16-116

ME	Credit Rates, Net Metering Rules	In June 2017, the state legislature passed a bill making significant changes to Maine's DG compensation policy, which the Governor then vetoed in early July. L.D. 1504 prohibits utilities from assessing fees for transmission or distribution (T & D) service relating to energy or demand supplied by customer self-generation. The bill also prohibits utilities from requiring customers to meter the gross output of eligible facilities in order to participate in net metering and requires net metering customers to be billed on the basis of "net energy", which is defined as the difference between the kWh delivered by the utility and exported by the customers during the billing period. This would once again allow behind-the-meter consumption of energy produced by customer-owned systems. The proposed legislation directs the Public Utilities Commission to amend the state's net metering rules by January 1, 2018 to implement these new provisions and allow 100% of eligible customers' net energy to apply to their T & D charges until December 31, 2021. The Commission's recently revised rules gradually reduce the percentage of net energy able to offset T & D charges. The bill also directs the PUC to submit a report to the joint standing committee of the legislature by January 1, 2021 with recommendations for transitioning from net metering to time-varying rates, market-based rates, or other rate designs. The report must examine how to promote DERs while supporting equitable treatment of all customers and application of cost causation principles, integrate DERs to increase the grid's efficiency and decrease cost, use AMI to track grid exports and usage and to provide actionable price signals, and encourage integration of and compensation for small-scale DERs in regional markets. The PUC must also conduct a cost-benefit analysis of net metering in an adjudicatory proceeding, examining all identifiable costs and benefits to both participants and non-participants. Maine's Governor vetoed the bill in early July 2017.	L.D. 1504
MI	Net Metering Rules	In December 2016, the Michigan legislature enacted S.B. 437 and S.B. 438. These bills direct the Public Service Commission (PSC) to develop a new distributed generation tariff program. The PSC shall approve these tariffs in rate cases filed after June 1, 2018. Prior to adopting a tariff, the PSC is to conduct a study on an appropriate tariff that reflects an equitable cost of service for utility revenue requirements for net metering customers. The enacted legislation also grandfathers customers participating in net metering prior to the adoption of a new tariff and reduced the maximum net metering application fee from \$100 to \$50. In July 2017, the PSC issued an order to continue current net metering	Docket No. 18383 S.B. 437 S.B. 438 Distributed Generation Program Updates

		tariffs until new DG tariffs are approved after June 1, 2018. Customers beginning to net meter under this program will be grandfathered under this program for 10 years from their enrollment date once new DG compensation tariffs are approved next year. Upcoming meetings are scheduled for October 18th, November 7th, and December 12th.	
MN	Net Metering Rules	In 2015, the Minnesota legislature amended a portion of the state's net metering statute applicable to cooperative and municipal utilities, allowing these utilities to charge additional fees to recover fixed costs not paid by net metering customers. In June 2016, following challenged filings to these fee proposals, the Minnesota Public Utilities Commission (PUC) initiated a generic investigation into the appropriate methodologies for these types of fees proposed by electric cooperatives. As directed by the PUC, all cooperative utilities currently charging or considering a fee of this type submitted their methodology in July 2017. The PUC accepted comments during the remainder of Q3 2017.	Docket No. 16-512
MO	Net Metering Rules	In September 2017, the Missouri Public Service Commission opened a docket to review the Commission's rules on cogeneration and net metering. The docket is intended to gather information and conduct a workshop. Stakeholders submitted comments on the effectiveness of the current rules and suggested changes to the rules through mid-October 2017.	Docket No. EW-2018-0078
NC	Credit Rates, Net Metering Rules	The North Carolina legislature weighed in on net metering for the first time with the passage of H.B. 589 in June 2017. The state does not currently have a statutory requirement for utilities to offer net metering. H.B. 589 requires each public utility to file revised net metering credit rates with the North Carolina Utilities Commission (NCUC) after an investigation of the costs and benefits of customer-sited generation. The rates approved by the NCUC must be non-discriminatory and ensure that net metering customers pay their full share of fixed costs. The bill states that this may include fixed monthly energy and demand charges. Existing net metering customers (as of the date the NCUC adopts a new tariff) may remain on their current net metering tariffs until January 1, 2027. H.B. 589 was signed by the Governor in July 2017.	H.B. 589
NH	Aggregate Cap, Credit Rates, Net Metering	On June 23, 2017, pursuant to H.B. 1116, the PUC issued a final order approving a net metering successor tariff and identifying future steps. The successor tariff retains customer behind-the-meter consumption and monthly netting, but delineates	H.B. 1116 Docket No. DE 16-576

Rules, System Size	certain charges (system benefits charge, stranded cost recovery charge, storm recovery charge, and the state electricity consumption tax (repealed in the state budget)) as non-bypassable. These charges, amounting to approximately 0.388 cents/kWh, will be applied to all kWh delivered by the utility to the customer. The successor also includes a reduced credit rate for monthly net excess generation. For systems up to 100 kW, this rate is equal to 100% of the retail energy and transmission charges plus 25% of the distribution charge (~14.61 cents/kWh total), and for systems greater than 100 kW, this rate is equal to the energy charge only. The successor tariff will go into effect September 1, 2017, and current net metering tariffs will be available until the end of December 2040 for customers initiating net metering before the 100 MW cap or the new tariff becomes effective. The new tariff does not include an aggregate capacity limit. The PUC's order also initiates a value of DER study to be conducted by a qualified consultant and used as the basis for further changes to the successor tariff. The PUC staff is to convene a working group of stakeholders to develop the study scope and timing; a final report regarding scope and timeline is to be filed within eight months. The order also approves four pilot programs, through which data will be collected and also used to inform a "Phase 2" successor tariff. The four pilot programs are: (1) time-of-use pilots for Eversource and Unitil, (2) a low and moderate income renewable energy pilot program, (3) a real-time pricing pilot to be implemented by the City of Lebanon with Liberty Utilities, and (4) a non-wires alternative pilot program. The PUC staff is also to convene a working group to discuss the pilot program designs once proposed by the utilities (excluding the City of Lebanon real-time pricing pilot). The PUC aims to have the pilot programs approved and initially implemented within 18 months. Two issues remain unresolved by the final order: (1) whether a sale or ownership transfer of the DG system site or system itself entitles the new owner to continue to be grandfathered under the former net metering tariff, and (2) whether expansions of or modifications to DG systems entitles the owner to continue to be grandfathered. In August 2017, the PUC issued an order addressing the unresolved issues related to grandfathering. The order clarifies that a transfer in ownership of a net-metered DG system will not affect its grandfathered status. Expansions and modifications will also not affect the system's grandfathered status unless (1) a system 100 kW or less expands by the greater of 20 kW or	Order No. 26,029 Order No. 26,047 Order No. 26,055

		50% of existing capacity or (2) a system greater than 100 kW expands by the greater of 50 kW or 100% of the customer's annual on-site load. Additionally, any expansion that causes the system to go from a small system (up to 100 kW) to a large system (more than 100 kW), or from a large system to an ineligible system will cause the system to lose its grandfathered status. The PUC issued an additional order in September 2017, stating that grandfathered net metering customers may switch to the new net metering tariff, but may not switch back to the original tariff. In August 2017, the stakeholder working group, ordered to be formed in the PUC's June 2017 successor tariff order, held its initial meeting In September 2017, the stakeholder working group filed its first quarterly progress report. The low and moderate income working group met October 3rd, the time-of-use working group is scheduled to meet October 19th, the value of DER group is to meet October 23rd, and the non-wires alternatives group will meet November 6th.	
NV	Aggregate Cap, Credit Rates	In December 2016, the Public Utilities Commission of Nevada (PUCN) approved a draft order restoring retail rate net metering in Sierra Pacific Power's territory. The order allows for an additional 6 MW of solar systems to net meter under the original net metering rules. Sierra Pacific Power filed a petition to reconsider the decision in January 2017. The PUCN issued a draft order in June 2017, denying Sierra Pacific Power's petition. A final order was published in early July, denying the petition and declaring it moot, given the enactment of A.B. 405.	Docket No. 16-06006 Final Order
	Credit Rates, Net Excess Generation, Net Metering Rules	In June 2017, the Governor signed A.B. 405 into law, increasing the credit rate for excess generation to nearly the retail rate for systems up to 25 kW. The first 80 MW of solar systems to enter new net billing agreements will be credited at a rate equal to 95% of the retail rate. This rate declines by 7% for every additional 80 MW added, to an ultimate floor of 75% of the retail rate. Customers will be locked into their rate for a period of at least 20 years. The Public Utilities Commission of Nevada (PUCN) opened a new, expedited docket to implement A.B. 405, and NV Energy filed its application to amend its tariffs in July 2017. NV Energy's application interpreted the new law in such a way that would have resulted in net billing, rather than net metering. At issue was the definition of "excess generation" and the netting period to determine which kWhs are categorized as "excess". NV Energy's proposal	A.B. 405 Docket No. 17-07026

		utilized an hourly netting period, while the Commission ruled that a plain language interpretation of A.B. 405 should be applied and a monthly netting period is to be used. NV Energy's application also sought to increase its monthly fixed charge for all customers. The PUCN's September 2017 order both granted and denied portions of NV Energy's application. The PUCN ruled that any rate design issues are to be dealt with in the utilities' general rate case proceedings.	
NY	Credit Rates, Net Metering Rules, System Size	As part of the New York Reforming the Energy Vision (REV) process, the Public Service Commission (PSC) is developing a methodology for DER valuation that provides a more precise and complete accounting of the values and costs of DERs than traditional net metering. While the PSC recognized that the development of an appropriate value and compensation for DERs will be an ongoing process that will proceed in tandem with technical and market capabilities, it directed the public staff to develop recommendations on the value of DERs that could potentially lead to an alternative to net metering. In March 2017, the PSC published a net metering transition order (Docket No. 15-E-0751), providing direction on how DERs should transition from net metering to a Value of Distributed Energy Resources (VDER) tariff that reflects the costs and benefits of DERs on the grid. The transition will occur in phases. In Phase I, mass market projects will be interconnected under existing net metering rules with 20-year contracts. All projects interconnected before the order will be grandfathered. Projects that do not qualify for Phase I net metering (community solar, remote net-metered projects, and large distributed energy projects) will be compensated through the Phase I Value Stack tariff. The Value Stack tariff will include monetary credits for net hourly electricity exported to the grid. Excess credits will carry over to subsequent billing and annual periods. Projects eligible for the Value Stack will have a 25-year contract term from their in-service date. The Value Stack for net hourly electricity exported to the grid will be calculated based on the total of 1) the energy value, based on day-ahead hourly zonal locational marginal price, 2) the capacity value, 3) the environmental value, and 4) the demand reduction value and locational system relief value. The utilities filed their Phase I implementation plans in May 2017. In September 2017, the PSC issued an order on Phase I VDER implementation. The Commission 1) approved the utilities' marginal cost of service studies	Docket No. 15-E-407 Docket No. 15-02703/15-E-0751

		2) approved the utilities' proposed methodologies for calculating the locational system relief value (LSRV), 3) directed utilities to use Orange and Rockland's methodology for determining capacity value (looking at peak kW to kWh; further refinements will be made in Phase 2), 4) directed utilities to identify average generation profiles using National Renewable Energy Laboratory data, 5) determined utility cost recovery provisions, and 6) approved base rate calculations and other implementation issues raised. The order also addressed the environmental compensation value and the eligibility of storage paired with clean generation for net metering and value stack compensation. The PSC directed the New York State Energy Research and Development Authority to develop a proposal for integrating storage into the interconnection process. The utilities are to file monthly VDER tariff statements beginning in November 2017. The September 2017 order also included steps to mitigate market barriers, bill impacts, and project costs. The PSC proposed an increase in the maximum size for net-metered projects from 2 MW to 5 MW (comments are due by November 20th). The PSC also addressed a process for implementation of consolidated billing.	
	Credit Rates	In March 2017, the New York Public Service Commission (PSC) issued a net metering transition order, addressing Phase I of the Value of Distributed Energy Resources (VDER) proceeding and outlining a procedure for Phase II of the proceeding. In May 2017, the PSC organized a conference, creating working groups and protocols for Phase II of the VDER proceeding. Three working groups have been established, looking at: (1) the value stack, (2) rate design, and (3) low and moderate income issues. The working groups will support the public staff to develop recommendations. The working groups met through Q3 2017.	Matter No: 17-01276 (Value Stack) Matter No: 17-01277 (Rate Design)
OH	Net Metering Rules	Net metering rules have been before the Ohio Supreme Court since July 2014. AEP Ohio alleges that the net metering rules issued by the Public Utilities Commission of Ohio (PUCO) illegally require payments to be made to customer-generators for electricity not generated by the company. PUCO submitted a joint status report, and the court extended the briefing schedule for an eleventh time in August 2017.	Ohio Supreme Court Case 2014-1290
RI	Net Metering Rules	In September 2017, Tesla and Sunrun petitioned the Public Utilities Commission (PUC) for a declaratory ruling on the net metering eligibility of solar systems	Docket No. 4743

		paired with energy storage. The petition is specifically concerned with solar PV systems less than 25 kW with battery storage systems that are charged solely from the PV system, and for which the customer is not on a time-of-use rate. The accepted comments in October 2017.	
SC	Credit Rates	In June 2017, Santee Cooper proposed changes to the credit rate for excess generation (netted hourly) under its distributed generation rider. Santee Cooper's proposal would reduce the export credit rate from \$0.0416/kWh (summer)/\$0.0384/kWh (non-summer) to \$0.0384/kWh (summer)/\$0.0372/kWh (non-summer) in 2018 and again to \$0.0384/kWh (summer)/\$0.0356/kWh (non-summer) in 2019. Public meetings were scheduled for August 2017; however, Santee Cooper's Board of Directors voted to suspend the rate adjustment activities in August 2017. The bankruptcy of Westinghouse led to the suspension of construction on the V.C. Summer nuclear plant, in which Santee Cooper had a financial interest. The escalating costs of the project had led Santee Cooper to propose new rates, but the suspension of the project makes the rate adjustment unnecessary.	Proposed Rates Santee Cooper Website
TX	Credit Rates	In SWEPCO's December 2016 general rate case, the utility proposed eliminating retail rate net metering and replacing it with an avoided cost buy-all, sell-all program. The new tariff would apply only to new DG customers; existing DG customers would remain under the current system. An ALJ issued a proposed decision in September 2017, recommending that the proposal be accepted with existing customers grandfathered for five years rather than indefinitely (the Commission Staff had opposed indefinite grandfathering). The Commission will consider the ALJ recommendations in an open meeting on November 17, 2017.	Docket No. 46449
UT	Aggregate Cap, Credit Rates, Net Metering Rules	In November 2016, Rocky Mountain Power (RMP) proposed a new tariff for net metering customers seeking interconnection after December 9, 2016. While one-to-one offsetting of customer production and consumption is preserved under the proposed tariff, the energy rate for energy consumed by the customer would be reduced to 3.8 cents per kWh, effectively reducing the credit rate for new net metering customers. The current energy rate for residential customers is structured as a seasonal inclining block rate, with rates ranging from 8.8 cents per kWh to 14.5 cents per kWh. In December 2016, the proposal was suspended to allow stakeholders to continue to seek mutually acceptable resolutions.	Docket No. 14-035-114 Docket No. 16-035-T14 Settlement Agreement Order Approving Settlement Stipulation

		A settlement agreement between the utility and solar advocates was filed in late August 2017. The settlement agreement closes net metering, as it currently exists, to new DG customers on November 15, 2017. New net metering customers must submit a complete interconnection application by midnight November 15th to be eligible for the current net metering program. Customers beginning to net meter by this data will be grandfathered under the current rules through December 31, 2035. If ownership of the property changes during this period, the system remains grandfathered. An Export Credit Proceeding will be conducted to determine the credit rate for energy exported to the grid by new DG systems, while on-site consumption will be permitted, essentially granting system owners a retail rate credit for this portion of the energy produced. As part of this proceeding, a workshop will be held to discuss the type and scope of data to be considered in determining the export credit rate. A transition program will be established by the Public Service Commission for customers applying to net meter after the current program closes and before the new export credit rate is decided. Transition customers will be eligible for net billing, rather than retail rate net metering, with an export credit rate of 9.2 cents/kWh for residential customers, netted in 15-minute intervals. However, if the state renewable energy systems maximum tax credit amount is less than $1,600 for 2019 and 2020, the export rate will increase to 9.4 cents/kWh. The settlement establishes an aggregate cap for the transition program of 170 MW for residential and small non-residential customers. As part of the agreement, the parties agree not to advocate for any changes to rates, charges, and fees for grandfathered net metering or transition customers that do not apply to the entire customer class. Customers submitting a complete interconnection application after this cap is reached will receive the transition credit rate until the new export rate is determined through the Export Credit Proceeding. The Commission approved the settlement in late September 2017.	
VA	Credit Rates	In August 2017, the Virginia State Corporation Commission initiated a proceeding to amend net metering regulations, pursuant to H.B. 2303, enacted in March 2017. After July 2019, all eligible agricultural customer-generators will be able to interconnect only as "small agricultural generators". Small agricultural generators will be credited through a buy-all, sell-all	Docket No. PUR-2017-00099

		arrangement at a non-retail rate. These customers are currently credited through retail rate net metering.	
	Net Metering Rules	The “Rubin Group”, an informal, invitation-only stakeholder group formed by utilities and the solar industry in Virginia is currently considering the future of net metering in the state. The working committee is not part of a regulatory or legislative proceeding. It has been reported that the group is considering a compromise based on time-varying rates. Details of the group’s discussions are not publicly available.	Virginia Solar Group Participants Warm to Time-of-Use Rates[7]
WI	Net Excess Generation	In June 2016, Superior Water, Light, and Power filed a general rate case with proposed rate design changes being submitted in August 2016. In addition to a residential fixed charge increase, the utility has proposed changes to its net metering tariff. The proposal would reduce the credit rate for monthly net excess generation from the retail rate to the avoided cost rate. Existing net metering customers and those beginning to net meter prior to January 1, 2018 will be grandfathered for 10 years. In August 2017, the Public Service Commission issued an order approving the proposed changes to the net metering tariff.	Docket No. 5820-UR-114

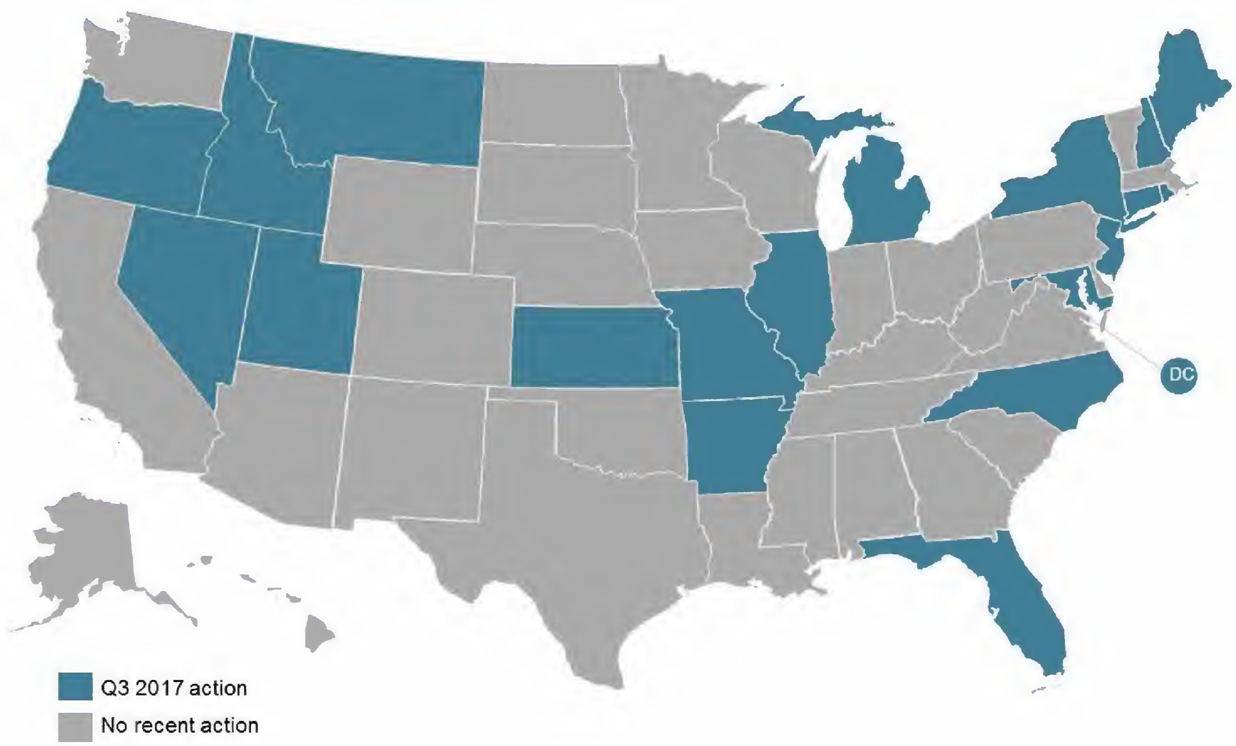
DISTRIBUTED SOLAR VALUATION STUDIES

Key Takeaways:

- In Q3 2017, 19 states plus DC were in the process of examining some element of the value of distributed generation.
- Regulators in four states – Kansas, New York, Oregon, and Rhode Island – made key decisions related to the value of distributed generation during the quarter.
- Two states – North Carolina and Utah – initiated new DG valuation efforts in Q3 2017.

Since the beginning of 2015, more than half of U.S. states have examined or resolved to examine the costs and benefits of distributed generation (DG), several of which have gone on to adopt changes to DG compensation policies. In Q3 2017, 19 states plus DC were engaged in the process of examining the value of distributed generation, with two states initiating new valuation efforts.

Figure 6. Action on Distributed Solar Valuation and Net Metering Studies (Q3 2017)



Two states – North Carolina and Utah – officially initiated new DG valuation efforts in Q3 2017. In North Carolina, the state's Governor signed H.B. 589 into law, which requires a net metering cost-benefit study to be completed and new credit rates to be determined. In Utah, the Public Service Commission approved a settlement agreement, part of which initiates a new export credit proceeding where the value of DG will be examined in developing this new compensation rate.

Other states, including Florida and Idaho, saw utility proposals to initiate new DG valuation efforts. A pending settlement agreement filed by Duke Energy Florida would include the collection of data on demand-side solar costs and benefits, while a proposal from Idaho Power would initiate an evaluation of DER costs and benefits to develop a new compensation structure.

Table 4. Upcoming DG Valuation Deliverables

State	Expected Date	Study Type
Maryland	December 2017	Distributed solar cost-benefit study
Michigan	March/April 2018	Net metering cost-benefit study
Montana	April 2018	Net metering cost-benefit study
New Hampshire	February 2017	Value of DER study scope
	No target set	Value of DER study
North Carolina	No target set	Net metering cost-benefit study
Oregon	July 2018	Utility-specific resource value of solar filings

Commissions in four states made important decisions related to the value of DG during the quarter. In Oregon, regulators adopted a resource value of solar methodology, including eleven separate elements, which will be applied to compensation rates for customers enrolled in the Solar Volumetric Incentive Program. Regulators in Rhode Island approved a benefit-cost framework with 22 power system-level, 5 customer-level, and 8 society-level categories of potential costs or benefits.

The New York Public Service Commission finalized its Phase I Value Stack methodology in Q3 2017; further refinements will be considered during Phase II of the proceeding. In Kansas, the State Corporation Commission also made a final determination within its DG valuation proceeding. The Kansas Commission decided that it is appropriate to separate DG customers into a separate customer class, which could include demand or other types of non-traditional charges for residential customers. The Commission also determined that DG customer rates should be based on cost of service, and not include any unquantifiable values, separating Kansas from the decisions made in New York, Oregon, and Rhode Island.

Table 5. Updates on Distributed Solar Valuation and Net Metering Studies (Q3 2017)

State	Description	Source
AR	In April 2016, the Arkansas Public Service Commission (PSC) opened a docket, pursuant to Act 827 of 2015, to ensure net metering rates, terms, and conditions are appropriate to recover the full utility costs to serve net metering customers, net of any quantifiable benefits. The proceeding was also initiated to investigate guidelines for approving non-residential net metering facilities over 300 kW. In August 2016, the PSC approved a unanimous proposal to bifurcate and establish a separate procedural schedule for issues relating to rates, terms, and conditions for net metering ("rate issues"). The PSC also approved a proposal to establish a Net Metering Working Group to address these rate issues. In September 2017, the Net Metering Working Group submitted its joint report and recommendations. The group has split into two sub-groups, with Sub-Group 1 (a group of solar advocacy organizations, environmental groups, and individuals), recommending a full study of the costs and benefits of net metering be conducted before adopting changes to net metering credit rates.	Docket No. 16-027-R Joint Report and Recommendations of the Net-Metering Working Group
CT	In February 2016, the Public Utilities Regulatory Authority (PURA) opened a docket to conduct a full Cost of Service Study (COSS) and rate design review to establish a standardized methodology for electric distribution companies to use. The review will be conducted in two phases – Phase I addressing the COSS and Phase II addressing rate design. In early April 2017, PURA determined that questions regarding the cost of serving DG customers should be explored in a new, separate docket. As of Q3 2017, the new docket has not yet been established.	Docket No. 16-02-30
DC	In June 2015, the DC Public Service Commission (PSC) initiated Formal Case 1130 to identify technologies and policies to modernize and increase the sustainability, reliability, and efficiency of the electric grid. The PSC staff submitted its Modernizing the Distribution Energy Delivery System for Increased Sustainability report in January 2017. The report identifies barriers to different aspects of grid modernization, including those related to DERs, and potential solutions to remove these barriers. In the same docket, the DC Office of the People's Counsel (OPC) filed a value of solar study in May 2017. The study, conducted by Synapse Energy Economics, estimated that the utility system total value of solar for 2017-2040 is \$13.266/kWh, while the societal total value is \$19.44/kWh. In June, the Commission approved PEPCO's request to initiate a comment period on the OPC value of solar study. Comments were accepted through mid-July 2017.	Formal Case No. 1130 OPC Value of Solar Study
FL	A proposed August 2017 settlement agreement primarily related to Duke Energy Florida's Levy Nuclear Plant calls for Duke to collect data on the economic and operational benefits and costs, to the extent that these can reasonably be identified, from the use of demand-side solar on its system. Duke will consider stakeholder input in the design of the data to be collected. This data will be used to support overall rate design, and Duke will share the information with stakeholders upon request prior to filing any rate design	Docket No. 20170183 Settlement

	changes. For the term of the settlement agreement, Duke agrees not to introduce new tariffs that impact rates on customers using demand-side solar without a cost of service study approved by the Public Utilities Commission or a Commission directive. A hearing is scheduled for October 25th.	
ID	In July 2017, Idaho Power requested that the Public Utilities Commission open a generic docket to develop a compensation structure for DERs based on the costs and benefits provided by DERs to the system. Idaho Power also requested that prior to the docket being opened, separate customer classes may be created for new residential and small general service with customer-sited generation. A hearing is scheduled for March 2018.	Docket No. IPC-E-17-13
IL	In March 2017, the Illinois Commerce Commission opened a proceeding to investigate grid modernization and the creation of a 21st century regulatory model. The NextGrid proceeding will be conducted as a facilitated stakeholder process. Topics include, but are not limited to (1) consumers, communities, and economic development; (2) grid design, digital networks and markets; (3) regulation and encouraging innovation; and (4) climate change and the environment. The process is very likely to include DG valuation and net metering considerations. Stakeholders filed initial comments during Q2 2017, with several recommending that DG costs and benefits, compensation, and rate structures be addressed. A conference and launch event for the proceeding took place in late September 2017. Working groups have been formed on seven topics: (1) new technology deployment and grid integration, (2) electricity markets, (3) customer and community participation, (4) regulatory, environmental, and policy issues, (5) metering, communications, and data, (6) reliability, resiliency, and cyber security, and (7) ratemaking.	Docket No. 17-0142 NextGrid Website
KS	In March 2016, the Kansas Corporation Commission filed a motion to request a general investigation of issues related to rate design for DG customers. This investigation was prompted by the determination in Westar's last rate case that such an investigation should be conducted. In July 2016, the Commission opened a general investigation to examine issues surrounding rate design for DG customers, including: evaluating the costs and benefits, examining alternative rate designs, and determining an appropriate rate structure. This proceeding is only expected to develop a policy for DG rate design. Any specific tariff changes will take place in utility-specific filings. In June 2017, the Commission staff, Westar, Kansas City Power & Light, and other parties filed a non-unanimous stipulation agreement that would allow utilities to create a separate customer class for DG customers, which could include demand charges, grid charges based on DG system size or output, and/or tiered customer charges based on the customer's capacity needs. A customer education program would be required with any new rate design approved. The stipulation further states that rates for DG customers should be cost-based and not include any unquantifiable values. The Commission issued a final decision in September 2017, approving the stipulation agreement.	Docket No. 16-GIME-403-GIE Non-Unanimous Stipulation Agreement

MD	In September 2016, the Maryland Public Service Commission (PSC), as part of the Exelon-PHI merger condition, initiated a grid modernization proceeding to make sure that the electric distribution system in Maryland is customer-centric, affordable, reliable, and environmentally sustainable. The proceeding will consider topics including rate design, costs and benefits of DERs, maximizing advanced metering infrastructure, valuing energy storage, streamlining the interconnection process, evaluating distribution system planning, and protecting limited income customers. The PSC held an initial public hearing in December 2016. A consultant will be hired to study the benefits and costs of distributed solar in Exelon-PHI territory, including solar's health and environmental benefits, examination of geographic and grid location, and how advancing energy storage technology and cost-effectiveness can enhance distributed solar's benefits. The study is targeted to be complete in December 2017, with a plan set to be proposed for a DER-specific pilot program with time-varying rates between January and May 2018. The rate design working group submitted a report detailing its two proposed time-of-use rate pilots, both of which net metering customers would not be eligible to participate in. A hearing regarding the time-of-use pilots was held in September 2017. *[See NCCETC's upcoming Q3 2017 50 States of Grid Modernization report for further detail on the time-of-use pilots.]*	Public Conference 44
ME	L.D. 1504 directs the Public Utilities Commission (PUC) to conduct an analysis of the costs and benefits to ratepayers from net metering in an adjudicatory proceeding. This study must include all identifiable costs and benefits to both net metering participants and non-participants and must examine costs and benefits over at least a 10-year and 25-year period. When there is uncertainty regarding a future cost or benefit, the PUC is to consider the most likely higher and lower value scenarios. In addition to this analysis, the PUC must submit a report to the joint standing committee of the legislature by January 1, 2021 with recommendations for transitioning from net metering to time-varying rates, market-based rates, or other rate designs. The bill was vetoed by the Governor in early July 2017.	L.D. 1504
MI	Legislation enacted in December 2016 directs the Public Service Commission (PSC) to conduct a study on an appropriate DG tariff that reflects an equitable cost of service for utility revenue requirements. At the initial DG working group meeting in March 2017, the PSC staff provided details on their plan to implement the legislation. The PSC staff proposed limiting the scope of this to solar and solar plus battery storage. The PSC will conduct a cost of service study, and PSC staff will aim to prepare a report on the study by January or February 2018, with a final report being published in March or April 2018. Parties will also be able to file their own studies and tariff filings for the PSC to consider. The study and tariff development must be completed by April 20, 2018. In early July, the PSC issued an order to continue current net metering tariffs until new DG tariffs are approved after June 1, 2018. Meetings are scheduled for October 18th, November 7th, and December 12th.	Docket No. 18383 S.B. 437 S.B. 438 Distributed Generation Program Updates

MO	In March 2017, the Missouri Public Service Commission (PSC) staff requested that the Commission open a workshop docket to gather information related the PSC's role in shaping the solar landscape, including Public Utility Regulatory Policies Act (PURPA), Missouri statutory provisions, net metering and cogeneration rules, avoided cost calculations, value of solar calculations, development and construction of utility-scale or community solar projects, and other states' activities. Information regarding the PSC's role in implementing modified rate design proposals, such as residential time-of-use rates, is also requested. The proceeding is also intended to examine issues surrounding advanced metering infrastructure, property assessed clean energy financing, and the electric vehicle market. A workshop held on May 18th featured discussion of all of these issues. Discussion on DG valuation concerned whether interested stakeholders should evaluate the value of DG or a study should be conducted by a neutral third party. In early July, the PSC staff issued a report recommending additional workshop to (1) address potential revisions to PSC rules regarding PURPA, avoided cost methodology, and net metering, (2) the needs of the value of distributed resources study (after progress is made in discussing avoided cost methodology), and (3) policy questions related to modified rate design proposals and data collection. A workshop will be held on November 20th, and another workshop is set to take place on January 9th. The deadline for submitting information for the first workshop is October 20th. The PSC's report is expected by March 2018.	Docket No. EW-2017-0245 Staff Report
MT	In May 2017, the Governor signed H.B. 219 in to law, which directs NorthWestern Energy to conduct a study of the costs and benefits of customer-generators and submit the study to the Public Service Commission (PSC) to make determinations in accordance with the utility's general rate case. After the study is submitted, the PSC may make a determination as part of the utility's general rate case that customer-generators should be served under a separate class of service. Customer-generator rates may be created including utility system benefits of net metering resources and the cost to provide service to customer-generators. Sub-classifications and rates may also be established, and the PSC may approve separate rates for customer-generators' production and consumption and require separate metering if it is necessary and appropriate. If a new class of service is established, existing customer-generators are grandfathered, but may elect to take service under the new classification. In June 2017, the PSC opened a docket, soliciting comments on the potential cost and benefit elements and questions to address in the study. Based on a review of cost-benefit studies conducted in other states, the PSC identified 11 benefits and 5 costs for potential inclusion in the study. In August 2017, following a comment period, the PSC established the final minimum study criteria, which includes 11 benefit categories (avoided energy costs, avoided capacity costs, avoided transmission and distribution capacity costs, avoided system losses, avoided RPS compliance costs, avoided environmental	H.B. 219 Docket No. D2017.6.49 Notice of Commission Action

	compliance costs, fuel hedging, avoided risk, avoided grid support services, avoided outages costs, and non-energy benefits) and 4 cost categories (reduced revenue, administrative costs, interconnection, and integration). The PSC noted that the study must address locational attributes of customer-generators and that NorthWestern Energy must describe a plan to enable better assessments of locational costs and benefits in the future. The PSC also directed the utility to use a 25-year timeframe for its analysis and provide results on a net present value basis using both the long-term risk-free rate and its own marginal cost of capital as discount rates. The study is due by April 1, 2018.	
NC	H.B. 589 directs the state's public utilities to file revised net metering rates with the NC Utilities Commission after an investigation of the costs and benefits of customer-sited generation is completed. The legislation does not explicitly state whether the utilities or the Commission will conduct the investigation. The Governor signed the bill in July 2017.	H.B. 589
NH	Pursuant to H.B. 1116 of 2016, the Public Utilities Commission (PUC) issued a final order approving a net metering successor tariff in June 2017. In the decision, the PUC ordered a value of DER study to be conducted by a qualified consultant under the Commission's guidance in order to inform "Phase 2" changes to the state's DG compensation policy. The study is to be a long-term avoided cost study using marginal cost concepts and incorporating both the Total Resource Cost and Ratepayer Impact Measure test criteria, as well as consideration of demonstrable and quantifiable net benefits associated with relevant externalities. The study period is to be 10-15 years - a compromise between the 3-5 years proposed by the coalition of utility and consumer parties and 25 years proposed by the coalition of solar and sustainable energy interests. The study will focus on solar PV and hydroelectric facilities. The PUC held an initial stakeholder working group meeting on August 16th, focusing on the organization and membership of the working groups. The value of DER study scope working group is scheduled to next meet on October 23rd.	Docket No. DE 16-576 Order No. 26,029
NJ	S.B. 2276 would establish the "NJ Solar Energy Study Commission" that would study all aspects of solar energy in the state. The bill passed the Senate in June 2016 and an Assembly floor amendment passed in June 2017.	S.B. 2276
	In September 2017, the New Jersey Board of Public Utilities initiated a generic proceeding on the state's solar market. The filings within the proceeding are not publicly accessible.	Docket No. QX17090949
NV	A.B. 405, signed into law in June 2017, requires the Public Utilities Commission of Nevada (PUCN) to open an investigatory docket to establish a methodology to determine the impact of net metering on electricity rates. The PUCN is required to submit a summary report of its findings to the legislature by June 30, 2020, and biennially thereafter. A docket was opened in July 2017.	A.B. 405 Docket No. 17-07013

NY	The Public Service Commission (PSC), in its July 2016 Order Establishing a Community Distributed Generation program, directed the PSC staff to initiate a proceeding to I) identify an interim approach to DER valuation, including a plan for moving from net metering to DER valuation that can be adopted prior to December 2016, and II) establish a methodology for a DER compensation mechanism based on the locational marginal price plus distribution (LMP + D) approach. In October 2016, the PSC staff released its report with recommendations for the interim valuation methodology and DER compensation. In March 2017, the PSC issued an order on the future of net metering in the state. The order is one of the major milestones in New York's Reforming the Energy Vision proceeding, addressing the transitional steps from traditional net metering to a Value of Distributed Energy Resources (VDER) tariff that accurately values and compensates DERs. Beginning March 9, 2017, community solar, remote net-metered projects, and large distributed energy projects will be compensated through the Phase I Value Stack VDER tariff that includes energy (based on LMP), capacity, environmental, and demand reduction credits. Mass market DER projects will be able to continue with the Phase I net metering tariff, which is identical to the previous net metering tariff, except that it includes a 20-year contract term. All projects interconnected prior to March 9, 2017 will be able to continue with traditional net metering. The utilities filed VDER implementation plans in May 2017. In September 2017, the PSC issued an order finalizing Phase I VDER implementation. Phase II work will continue to refine and improve the value stack, address rate design issues, and support participation for low to moderate income ratepayers.	Docket No. 15-02703/15-E-0751
	In March 2017, the New York Public Service Commission (PSC) issued a net metering transition order, addressing Phase I of the Value of Distributed Energy Resources (VDER) proceeding and outlining a procedure for Phase II of the proceeding. Phase II includes discussion of several topics, including a framework for development and consideration of grid access charges and other non-bypassable fees, potential changes to default rate design and new optional rates, improvements and modifications to the value stack (including components related to the bulk system, distribution system, and societal values), and transitioning of mass market projects to the VDER tariff. In May 2017, the PSC organized a conference, creating working groups and protocols for Phase II of the VDER proceeding. Three working groups have been established, looking at: (1) the value stack, (2) rate design, and (3) low and moderate income issues. The working groups will support the public staff to develop recommendations. The working groups met through Q3 2017.	Matter No: 17-01276 (Value Stack) Matter No: 17-01277 (Rate Design)
OR	The Public Utility Commission of Oregon (PUC) is continuing its investigation into the resource value of solar (RVOS). The RVOS will be sued to compensate systems enrolled in the Solar Volumetric Incentive Program after their 15-year payment schedule	Docket No. UM 1716 Order No. 17-357

	has expired. However, the RVOS could be utilized in other ways in the future as well. The PUC held several workshops and hearings throughout 2015, 2016, and 2017 to identify elements to include in the valuation and the methodology for calculating them. In September 2017, the PUC issued Order No. 17-357, formally closing Phase I of the proceeding and adopting the RVOS. The RVOS utilizes eleven elements (energy, generation capacity, transmission and distribution capacity, line losses, administration, market price response, RPS compliance, integration and ancillary services, hedge value, environmental compliance, and security, reliability, and reserves) for calculating an hourly avoided cost load profile for each year of the life of a solar PV system. To initiate Phase II of the proceeding, the PUC directed the utilities to make their RVOS filing in utility-specific dockets by November 30th. The PUC hopes to approve the utility-specific RVOS filings by July 2018.	
RI	In January 2016, the Public Utilities Commission (PUC) approved National Grid's request to withdraw its proposed alternative rate design. However, the PUC determined that it was important to continue to review the issues raised in the proceeding. In March 2016, the PUC opened a docket to identify and measure the costs and benefits of net metering and DERs. The stakeholder group's was managed by a third-party consultant, and the group met nine times between May 2016 and March 2017. The group released a final draft of the report in late March, and submitted a complete final version in early April. The working group developed a detailed Benefit-Cost Framework that may be used to evaluate DG programs and alternative rate designs, as well as recommendations on how rate design should evolve in the state. In May 2017, the PUC accepted the stakeholder report and directed its staff to develop a guidance document, which will be made available for public comment. The PUC also required National Grid to submit an examination of its rate design for low-income customers. A written order was issued in late July 2017. The guidance document was published in August 2017, and the PUC accepted comments until September. The guidance document shows the PUC's approach to the issue, but does not have any binding legal authority. The document includes the PUC's approach to rate design principles and a cost-benefit framework for future rate proceedings and program evaluations.	Docket No. 4600 Stakeholder Process Document Repository Report and Order
	H.B. 5318 and S.B. 880 amend the state's requirement for the Public Utilities Commission to conduct a study of the cost of including the distribution charge as part of the net metering calculation. Previously the statute required the Commission to conduct the study by June 30, 2019, but S.B. 880 moves up this deadline by one year to June 30, 2018. H.B. 5318 directs the Commission to study the benefits as well as the costs of including this charge in the net metering calculation. Both bills became effective without the Governor's signature in early July 2017.	H.B. 5318 S.B. 880

UT	In November 2016, Rocky Mountain Power (RMP) proposed a new tariff for net metering customers seeking interconnection after December 9, 2016. Parties filed testimony during June 2017. As part of the Utah Division of Public Utilities' testimony, the Division recommended opening a separate docket to evaluate possible DG costs and benefits with stakeholder input to determine a new export compensation rate. In a settlement agreement filed in August 2017 and approved in September 2017, parties agreed that a separate proceeding will be initiated to determine a new export compensate rate for DG systems. Participating parties will be able to present "evidence addressing reasonably quantifiable costs or benefits or other considerations they deem relevant." The Public Service Commission will determine the study period length for quantifying and modeling credit rate components.	Docket No. 14-035-114 Settlement Agreement Order Approving Settlement Stipulation

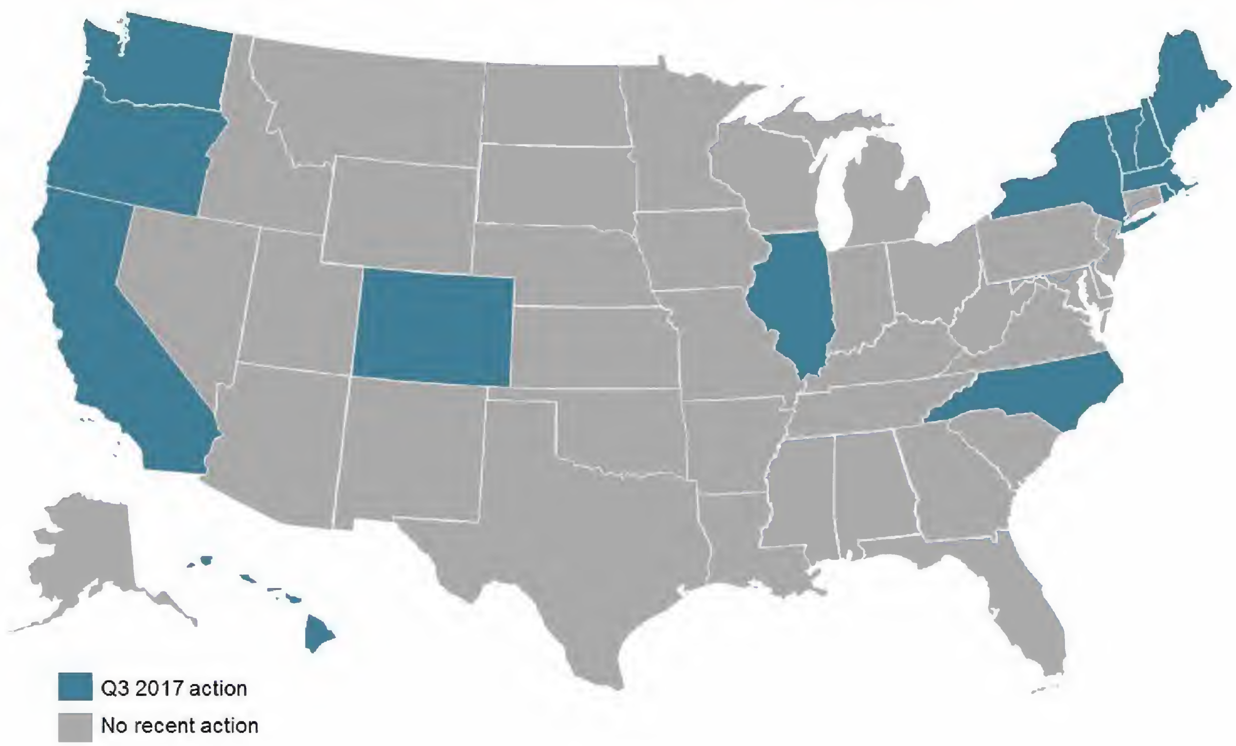
COMMUNITY SOLAR POLICY

Key Takeaways:

- In Q3 2017, 13 states considered changes to state community solar policy or community solar programs arising from state policy.
- Utilities Commissions in two states – Illinois and North Carolina – initiated rulemaking proceedings to establish community solar regulations, per recently enacted legislation.
- Three states – Hawaii, New York, and Oregon – continued regulatory proceedings to determine the value of credits for community solar participants.

Community solar programs offer the potential to expand solar access to a greater number of individuals and businesses. The community solar model often meets the needs of customers who desire access to solar energy, but do not have the physical, financial, or situational ability to install rooftop panels on their residence or workplace. Community solar facilities also have the potential to utilize economies of scale, making the cost of these projects typically cheaper than that of rooftop solar.

Figure 7. Action on Community Solar Policy (Q3 2017)

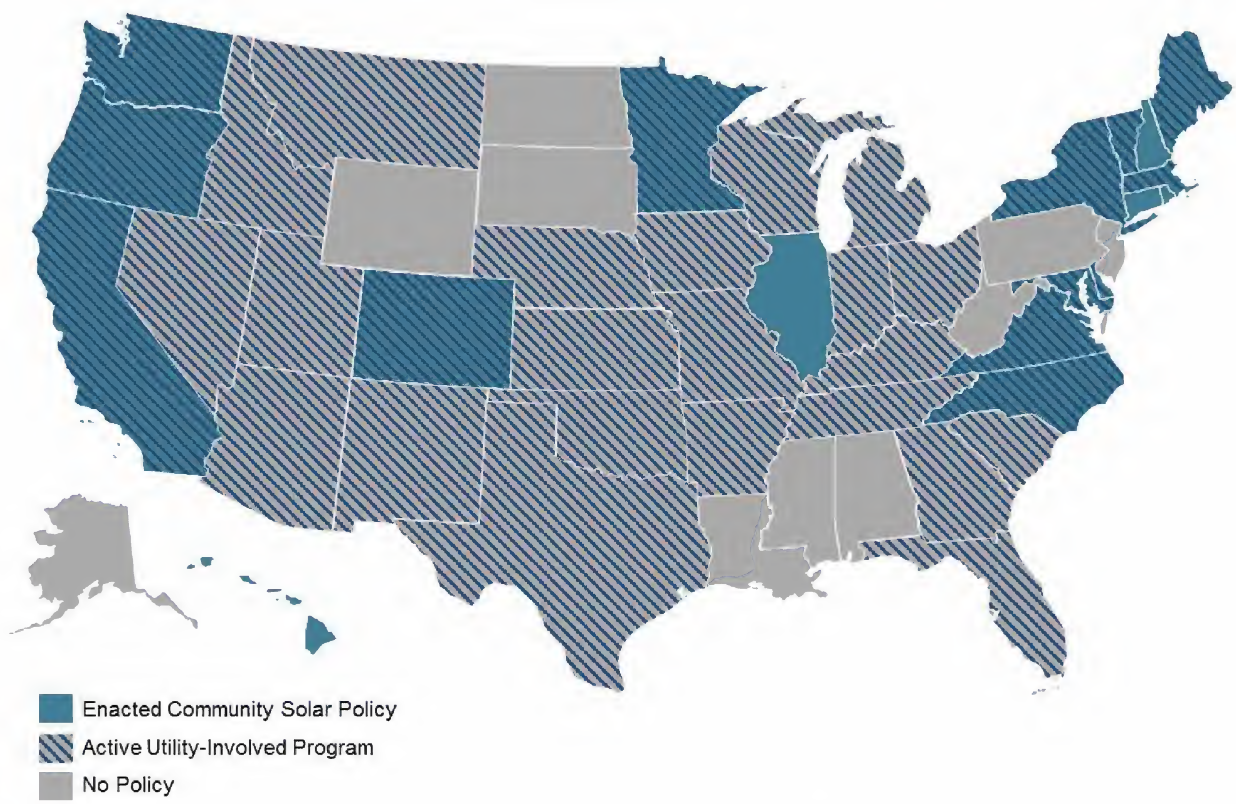


The benefits and flexibility of community solar programs also come with challenges for state legislatures and utilities commissions. State legislators and regulators are tasked with developing community solar policies and rules, including important decisions on program capacity limits, individual system size limits, participant credit rates, and eligibility criteria for

project ownership and participation. While several states have adopted community solar rules, each state's program is unique.

As of October 2017, 18 states and DC had statewide policies supporting community solar, and utilities in at least 35 states have active community solar programs, according to the Smart Electric Power Alliance (SEPA).[8] SEPA found that 171 utilities have active community solar programs, with at least 23 new programs launching across 15 states so far in 2017.[9] Notably, this is up from 83 active programs at the end of 2015.[10]

Figure 8. State Community Solar Policies & Utility Community Solar Programs



Source: NC Clean Energy Technology Center; Smart Electric Power Alliance[11]

In Q3 2017, North Carolina became the latest state to adopt a community solar policy. H.B. 589, signed by North Carolina's governor in July 2017, directs Duke Energy to propose a community solar program according to certain guidelines. While these are the first statewide community solar rules for North Carolina, multiple municipal and cooperative utilities in the state have already developed community solar programs. Notably, Fayetteville Public Works Commission, a large municipal utility in the state, recently issued an RFQ for a community solar plus battery storage project.

Illinois also took a major step forward toward implementing its community solar legislation in Q3 2017. The Illinois Power Agency published its draft long-term renewable resources procurement

plan, which includes proposed community solar program details. The draft describes a low-income community solar incentive program, as well as a competitive-bid process for community solar projects. Illinois' investor-owned utilities each submitted a proposed community net metering tariff in September 2017, all of which were later approved.

While most community solar programs credit participants at the retail rate, there are a number of proceedings examining a wide range of credit values for community solar programs. H.B. 589, enacted in North Carolina in July 2017, requires community solar subscribers to be credited at the avoided cost rate, and community solar tariffs filed in Illinois will credit projects at the energy supply rate, but not offer credit for the transmission and distribution components of the utilities' rates.

At the other end of the spectrum, final rules for Massachusetts' new Solar Massachusetts Renewable Target (SMART) incentive program will provide an adder for community solar and low-income projects, bringing compensation above the retail rate. Other states, including Minnesota, New York, and Oregon have been leading the development of community solar credit rates that are based on the value of solar, while Hawaii is examining time-varying credit rates.

Box 4. What is Community Solar?

Community solar refers to a voluntary program for customers where a solar PV system "provides power and/or financial benefits to, or is owned by, multiple community members."[12] While some community solar projects share similarities with utility-scale solar projects (e.g., large in size, located off-site from consumption, ground-mounted systems, utility-side of the meter), this report, which focuses on distributed solar, includes policy actions related to these programs because they are community-focused and provide residential customers a way to invest in solar energy. Community solar programs included in this report may be administered by a utility or third party, but are enabled or mandated under state rules encouraging the development of such programs. Community solar is also sometimes referred to as "shared solar," or "solar gardens." Policies that enable these programs include "virtual" or "remote" net metering, in which net metering is expanded to apply to customers who have invested in an offsite PV system.

An aspect of community solar receiving special attention is enabling access to community solar for low-income customers. In Q3 2017, New Hampshire passed legislation to provide community solar project financing to low and moderate income customers, and Massachusetts published its final SMART program rules, which provide bonus incentives for low-income community solar projects. Illinois is also developing a low-income community solar incentive program.

Table 6. Updates on Community Solar Policies (Q3 2017)

State	Description	Source
CA	S.B. 366, which would amend the state's Green Tariff Shared Renewables Program rules passed its first chamber in May 2017. The proposed legislation would increase the aggregate capacity limit of the program from 600 MW to 800 MW. The bill would also make it easier for disadvantaged communities to participate. The bill passed the Senate in May 2017, but has not seen any action since July, when a hearing on the bill was canceled.	S.B. 366
	A.B. 1573 would amend the state's Green Tariff Shared Renewables Program, increasing the maximum eligible system capacity limit from 20 MW to 30 MW. The bill passed the Assembly in May 2017, but has not seen any action since June, when a hearing on the bill was canceled.	A.B. 1573
CO	In February 2017, Public Service Company of Colorado d/b/a Xcel Energy filed a petition for a declaratory order on whether the utility may accept bids from community solar developers at negative prices for RECs. The issue has come up in two previous solicitations, but was resolved by negotiated settlements. A hearing was held in early October 2017.	Docket No. 17D-0082E
HI	S.B. 2010, enacted in May 2015, allows any person or entity to "own or operate an eligible community-based renewable energy (CBRE) project." In June 2016, the Public Utilities Commission (PUC) filed a draft proposal, identifying the core elements and parameters of a CBRE program. In February 2017, the PUC proposed a CBRE program framework and model tariff language, based on input from its June 2016 proposal. The proposed framework includes island-specific capacity additions, credit rates, and project size stipulations, as well as time-differentiated pricing. The PUC held a technical conference over two days in June 2017 to solicit input on the issues raised by the parties in response to its proposed framework. In August 2017, the PUC held a non-evidentiary hearing on Kauai Island Utility Cooperative's motion that the CBRE should not apply to the utility.	Docket No. 2015-0389
IL	The Future Energy Jobs Act, which went into effect in June 2017, created a community renewable generation program. In September 2017, the Illinois Power Agency published its Long-Term Renewable Resources Procurement Draft Plan, which sets out details of the community solar program. Community solar projects are included in the adjustable block purchasing program for renewable resources, and community solar subscribers are eligible for net metering, with investor-owned utilities being required to submit community solar net metering tariffs by September 27, 2017. The draft plan also describes a low-income community solar incentive plan that provides extra funding of \$69.23-\$129.56 per REC (depending on utility and total capacity of the project) for community solar projects subscribed to by low-income customers. The draft plan also includes a competitive-bid procurement process for low-income community solar pilot projects, which will be a separate program from the incentive program. The Illinois Commerce Commission will review the IPA's procurement plan. Comments on the plan are due by November 13th.	Docket No. 17-0392 IPA Long-Term Renewable Resources Procurement Draft Plan

	As required by the Future Energy Jobs Act, Commonwealth Edison (ComEd) filed a tariff for community solar net metering in August 2017. All electricity generated by community solar projects will be credited at the rate of the electric supply charge under ComEd's Basic Service tariff, equaling approximately 5.5 to 5.8 cents per kWh, depending on the season. The tariff was approved by the Illinois Commerce Commission in September 2017.	Docket No. 17-0350
	As required by the Future Energy Jobs Act, MidAmerican Energy filed a tariff for community solar net metering in August 2017. The tariff compensates community solar generation at a rate that includes the electricity supply charges, but not the transmission and distribution charges. Any unsubscribed community solar generation is credited as a PURPA qualifying facility. The tariff was approved by the Illinois Commerce Commission in September 2017.	Docket No. 17-0368
	As required by the Future Energy Jobs Act, Ameren Illinois filed a tariff for community solar net metering in August 2017. The tariff became effective in late September. The Illinois Power Agency's draft plan describes Ameren's tariff changes as a complete revision to Ameren's Rider NM (Net Metering).	Tariff Filing No. ERM 17-144 IPA Long-Term Renewable Resources Procurement Draft Plan
MA	In January 2017, the Department of Energy Resources (DOER) released its final program design for the solar incentive program that will succeed the existing SREC II Program. The new program, called Solar Massachusetts Renewable Target (SMART), is a 1,600 MW declining block program. Small projects will receive a 10-year fixed price term, and large projects will receive a 20-year fixed price term. The maximum eligible project size is 5 MW. Base incentive rates vary by project size, and adders are included for community solar projects ($0.03) and low-income community solar projects ($0.06). DOER filed an emergency regulation to implement the program in June 2017 and held three public hearings in July. In August 2017, DOER published the final version of the regulation.	DOER Next Solar Incentive Landing Page 225 CMR 20.00
ME	In June 2017, the state legislature passed a bill making changes to Maine's community net metering policy. The proposed legislation increases the number of customers that may participate in a shared renewable energy facility from 10 to 200, except for transmission and distribution utilities operating in the area administered by the Independent System Administrator for Northern Maine. If the Public Utilities Commission determines a utility's billing system can accommodate more than 10 accounts per facility in this region, this limit may be exceeded. The bill was vetoed by the Governor in July 2017.	L.D. 1504
NC	H.B. 589 authorizes and establishes rules for community solar. The proposed legislation directs Duke Energy Carolinas and Duke Energy Progress to file plans for community solar programs limited to 20 MW. Each community solar facility may be up to 5 MW, and must have at least five subscribers. A single subscriber may not have more than a 40% interest in the facility, each subscription must be at least 200 W, and a participant may only subscribe up to 100% of their maximum	H.B. 589 Docket E-100 Sub 155

	annual peak demand. Community solar facilities must be located in the offering utility's service territory, and participants must be located in the same county or contiguous county to the community solar facility (exceptions for distances up to 75 miles may be granted by the Utilities Commission if it is in the public interest). Participants will be credited at the utility's avoided cost rate, and the program must hold non-participating customers harmless. Subscribers must also be offered the option to own the RECs associated with the energy produced by the community solar facility. The Governor signed H.B. 589 into law in July 2017. In late August 2017, the North Carolina Utilities Commission initiated a rulemaking to implement the legislation. Initial comments are due by October 25th.	
NH	Among other changes, S.B. 129 requires that at least 15% of funds from the state's Renewable Energy Fund be used to benefit low to moderate income residential customers, including financing low to moderate income community solar projects in manufactured housing communities or multi-family rental housing. The bill also allows members of group net-metered low to moderate income community solar projects to receive credits on their electric bills, provided that only one new project functioning in this manner will be available in each utility's service territory by December 31, 2019. The Public Utilities Commission is to report on the costs and benefits of these projects by December 31, 2019. The bill became law without the Governor's signature in July 2017.	S.B. 129
NY	In July 2015, the New York Public Service Commission (PSC) issued an order establishing community net metering. Implementation of the program is divided into two phases. During the first phase, projects will be limited to siting DG in areas where it provides the greatest locational benefits to the larger grid and in areas that promote low-income customer participation. The community net metering projects will be fully implemented throughout utility service territories in the second phase of implementation. In August 2016, the PSC Staff, after a collaborative process, issued a report on the development of means to encourage low-income customer participation in community distribution programs. The staff recommended that the Commission suspend the collaborative process and instead have the Commission staff address the issue in a white paper. The Public Staff is currently working on a white paper concerning community DG for low-income customers and previously requested comments on 1) the development of a standardized customer disclosure statement, 2) application of certain Home Energy Fair Practices Act provisions, and 3) the role of utility-sponsored community DG projects.	Docket No. 15-E-0082
	In March 2017, the Public Service Commission (PSC) issued an order on the future of net metering in the state that has immediate implications for community solar projects. The order is one of the major milestones in New York's Reforming the Energy Vision proceeding, addressing the steps to transition from traditional net metering to a Value of Distributed Energy Resources (VDER) tariff that accurately values and compensates DERs. Beginning March 9, 2017, community solar, remote net-metered projects, and large distributed energy projects will be compensated through the Phase I Value Stack VDER tariff that includes energy (based on LMP), capacity, environmental,	Docket No. 15-02703/15-E-0751

	and demand reduction credits. All projects interconnected prior to March 9, 2017 will be able to continue with traditional net metering. In April 2017, a New York resident filed a petition for the PSC to modify its VDER order in order to allow Market Transition Credit (MTC) compensation for small customer tenants in master-metered buildings and to clarify that sub-metered residential and small commercial customers are eligible for the MTC. An organizational conference on Phase II of the VDER proceeding was held in May 2017 and a technical conference in June. Phase II includes discussion of several topics, including improvements and modifications to the value stack (including components related to the bulk system, distribution system, and societal values). In June 2017, the PSC established three working groups: one each to cover the value stack, rate design, and low to moderate income issues. Working group meetings were held in mid-July 2017.	
OR	S.B. 1547 of 2016 established a community solar program for the state. The legislation sets basic criteria and directs the Public Utility Commission (PUC) to establish the rules for the program, which must require utilities to enter into 20-year power purchase agreements with certified projects and incentivize customers to participate while minimizing cost shifts and financial burdens. The PUC opened a docket to initiate a rulemaking and held two staff workshops in 2016 and two additional staff workshops during Q1 2017. The PUC issued proposed rules in April 2017, and after accepting comments, adopted the proposed rules in June 2017. While the rules provide guidance on many aspects on community solar, certain issues will not be fully addressed until the Program Implementation Manual is developed and adopted by the PUC. The PUC is also continuing to develop the Resource Value of Solar (see DG Valuation section), which will be the bill credit basis for community solar participants. There are multiple implementation actions that must be taken before the community solar program is launched, including selection of a third-party administrator for the program. In September 2017, the PUC approved the staff's recommendation to commence a stakeholder process to identify and scope all of the implementation actions that must be taken.	S.B. 1547 Docket No. AR 603 PUC Order with Community Solar Program Rules
RI	In July 2017, the Governor signed H.B. 5618 into law, expanding eligibility for virtual net metering to educational institutions, hospitals, and non-profit entities.	H.B. 5618
VT	In July 2017, the Vermont Public Utilities Commission initiated a proceeding to evaluate standards and procedures for reviewing requests to attribute more than one net metering project to a net metering group. In early October 2017, the Commission issued a final order, adopting standards and procedures for reviewing these requests. The Commission incorporated Green Mountain Power's two requested additions, requiring a statement of the cumulative capacity of the net metering group and an affirmation that the new, merged group will not put any single customer over the 500 kW system capacity limit.	Docket No. 17-3604-INV
WA	Subscribers to community solar projects in Washington are eligible to receive payments under the Renewable Energy Cost Recovery	S.B. 5939

Incentive Program. This program was scheduled to end in 2020 with no payments made after that date. S.B. 5939, signed in July 2017, extends the program through 2030, changes the incentive rate paid for community solar projects, and increases the maximum eligible size of a community solar project from 75 kW to 1 MW.

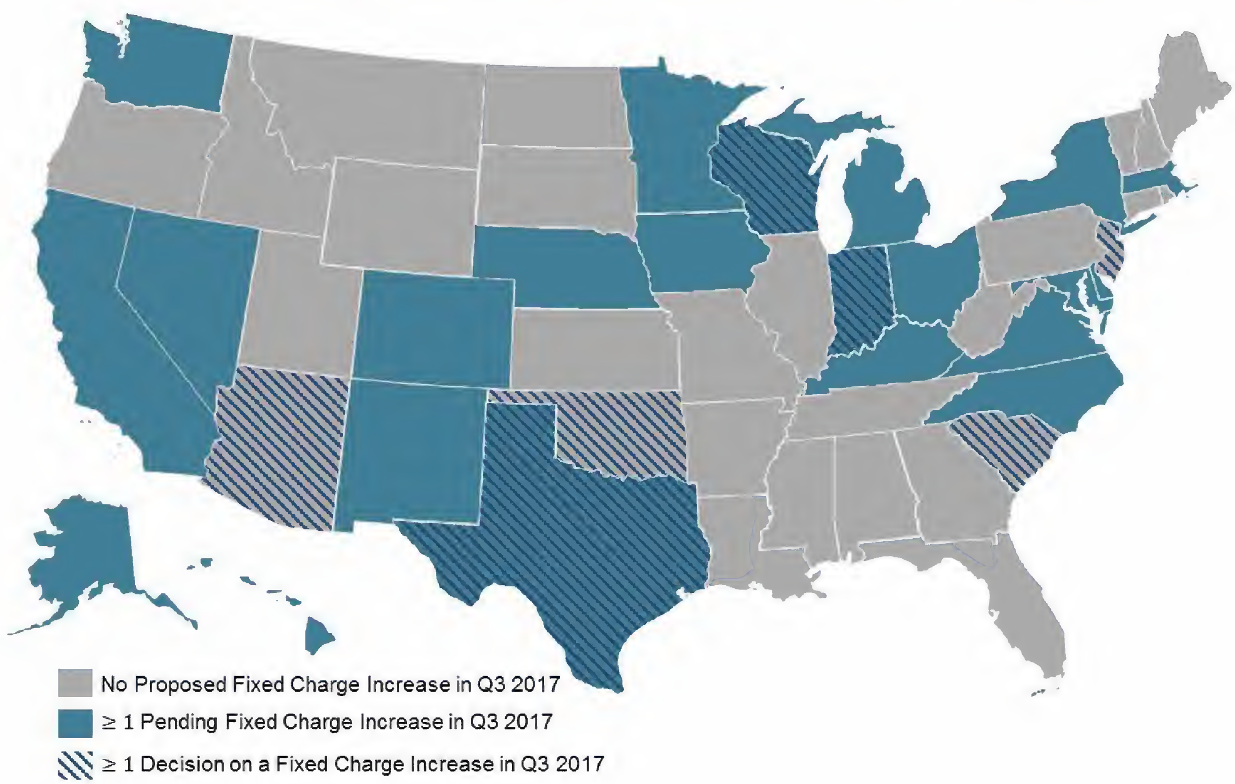
FIXED CHARGES AND MINIMUM BILLS

Key Takeaways:

- In Q3 2017, 42 utilities in 26 states and DC had pending or decided proposals to increase residential fixed charges by at least 10%.
- Two utilities in Hawaii also proposed residential fixed minimum bill increases of at least 10%.
- Eight fixed charge decisions were made in Q3 2017, with three utilities receiving no increase, four utilities receiving a partial increase, and one utility receiving its full requested increase.
- Overall, the median increase requested was $4.00, and the median percentage increase requested was 39% (average of 65%). Proposals ranged from an increase of $0.91 to $16.77.

Utility requests to increase residential fixed charges continued in Q3 2017, with 42 utilities in 26 states and DC having pending or decided proposals to increase residential fixed charges by at least 10% during the quarter (plus two requests to increase minimum bills). Eleven utilities proposed new fixed charge increases of at least 10% during Q3 2017.

Figure 9. Proposed Increases to Residential Fixed Charges (Q3 2017)



The median percentage increase requested among new, pending, and decided proposals was 39% during Q3 2017, while the average was 65%. Nine investor-owned and two large public power utilities proposed new fixed charge increases of at least 10% in Q3 2017. Among these proposals, the average requested increase was $4.81 (median of $4.01), or 52% (median of 33%).

Eight decisions were made during Q3 2017, with three utilities (*Empire District Electric – OK, Santee Cooper – SC, and Sharyland Utilities – TX*) receiving no increase and four utilities (*Arizona Public Service – AZ, PEPCO – DC, Southern Indiana Gas & Electric – IN, and Atlantic City Electric – NJ*) receiving a partial increase. One utility (*Superior Water, Light, and Power – WI)* received its full requested increase.

Table 7. Residential Fixed Charge Decisions (Q3 2017)

State	Utility	Amount of Increase Granted	% Increase Granted	% of Initial Request Granted
AZ	Arizona Public Service	$2.63	25%	19%
DC	PEPCO	$2.09	16%	56%
IN	Southern Indiana Gas & Electric	$7.00	64%	52%
NJ	Atlantic City Electric	$0.56	13%	36%
OK	Empire District Electric	$0.00	0%	0%
SC	Santee Cooper	$0.00	0%	0%
TX	Sharyland Utilities	$0.00	0%	0%
WI	Superior Water, Light, and Power	$2.00	29%	100%
Q3 2017 MEDIAN		**$1.28**	**15%**	**28%**
Q3 2017 AVERAGE		**$1.79**	**18%**	**33%**

Unique circumstances played a role in the decisions in multiple utilities' rate cases during Q3 2017. In South Carolina, the proposed rate increase was deemed unnecessary at this time as a result of the decision to halt construction on the V.C. Summer nuclear plant. In Oklahoma, Empire District Electric's acquisition by Liberty utilities led the Commission to reject the proposed rates. Sharyland Utilities in Texas was acquired by Oncor, leading to dismissal of its rate case.

The average increase granted in Q3 2017 was 18%, with utilities receiving 33% of their requested increase on average. There were 36 requests to increase residential fixed charges or minimum bills pending at the end of Q3 2017. The largest pending requests are: (1) Duke Energy Ohio ($16.77; 280%), (2) Dayton Power Light ($9.48; 223%), (3) Duke Energy – Kentucky ($6.72; 149%) (4) Indiana Michigan Power – MI ($10.70; 147%) and Indiana Michigan Power – IN ($13.46; 147%), and (5) Ohio Power Company d/b/a AEP ($10.00; 119%).

Table 8. Updates on Increases to Residential Fixed Charges (Q3 2017)

State	Utility	Monthly Residential Fixed Charge			Description	Source
		Existing	Proposed	Approved		
AK	Alaska Power Company	$13.85	$20.00	*Pending*	In July 2016, Alaska Power Company requested an increase in its residential monthly fixed charge. The original filing was rejected, as it did not comply with the Regulatory Commission of Alaska's requirements. The company made a supplemental filing in August 2016 to comply with these requirements. A stipulation was filed in September 2017, which includes the full fixed charge increase.	Docket No. TA857-2 Docket No. U-16-078 Stipulation
AZ	Arizona Public Service	$10.37	$14.51* or $24.00*	$13.00	In June 2016, Arizona Public Service (APS) proposed an increase in its residential monthly fixed charge. The rate case proposes three rate options for residential customers (as well as a fourth option available only to customers with very low consumption). Two of the options include a fixed charge of $24.00, and one includes a fixed charge of $14.51. Each of the three options includes time-of-use rates. A settlement agreement among 30 parties, including major solar advocacy groups, was filed in March 2017. The agreement includes four rate options for residential DG customers: two three-part rates with $13 fixed charges, a time-of-use rate with a $13 fixed charge, and a pilot three-part rate for DG customers with a $15 fixed charge. The standard two-part	Docket No. E-01345A-16-0036 Settlement Agreement Decision No. 76295

					residential tariff not available to DG customers includes a $15 fixed charge. The agreement was approved in August 2017.	
CA	Riverside Public Utilities	$8.06	$13.21	*Pending*	In August 2017, Riverside Public Utilities submitted a proposal to the Board of Public Utilities and the City Council for a rate increase over the next five years. The proposal includes an increase in the customer charge every year starting in FY 2018, resulting in a customer charge of $13.21 in FY 2022.	Proposed Rates RPU Website
CO	Black Hills Energy	$16.50	$20.13	*Pending*	In July 2017, Black Hills Energy requested an increase in its residential monthly fixed charge. The utility is also proposing a shift from declining season tiered rates to a year-round inclining block rate for standard residential customers. The energy rate for residential net metering customers would be a year-round single tier rate.	Docket No. 17AL-0477E
DC	PEPCO	$13.00	$16.75	$15.09	In June 2016, PEPCO requested an increase in its residential monthly fixed charge. In July 2017, the Public Service Commission approved a portion of PEPCO's proposed fixed charge increase. In August 2017, multiple parties filed applications for reconsideration. In September 2017, the Commission extended the deadline for action on these applications until October 25th.	Formal Case No. 1139
DE	Delmarva Power & Light	$11.70	$13.51	*Pending*	In August 2017, Delmarva Power & Light requested an increase in its residential	Docket No. 17-0977

					monthly fixed charge. A Commission hearing is scheduled for June 2018.	
HI	Hawaiian Electric Company (HECO)	$9.00	$14.00	*Pending*	In December 2016, Hawaiian Electric Company proposed an increase in its residential monthly fixed charge.	Docket No. 2016-0328
	Hawaiian Electric Company (HECO)	$17.00 (Min. bill)	$25.00 (Min. bill)	*Pending*	In December 2016, Hawaiian Electric Company proposed an increase in its residential monthly minimum bill.	Docket No. 2016-0328
	Hawaiian Electric Light Company (HELCO)	$10.50	$14.50	*Pending*	In September 2016, Hawaiian Electric Light Company proposed an increase in its residential monthly fixed charge. The PUC approved an interim decision in August 2017, which includes an interim increase in revenues.	Docket No. 2015-0170 Interim Decision and Order 34766
	Hawaiian Electric Light Company (HELCO)	$20.50 (Min. bill)	$25.00 (Min. bill)	*Pending*	In September 2016, Hawaiian Electric Light Company proposed an increase in its residential monthly minimum bill. The PUC approved an interim decision in August 2017, which includes an interim increase in revenues.	Docket No. 2015-0170 Interim Decision and Order 34766
IA	Interstate Power & Light d/b/a Alliant Energy	$10.50	$13.50	*Pending*	In April 2017, Alliant Energy proposed an increase in its residential monthly fixed charge. A hearing was held in October 2017.	Docket No. RPU-2017-0001
IN	Indiana Michigan Power	$7.30	$18.00	*Pending*	In July 2017, Indiana Michigan Power requested an increase in its residential monthly fixed charge.	Docket No. 44967
	Southern Indiana Gas & Electric d/b/a Vectren	$11.00	$24.46	$18.00	In February 2017, Vectren Energy requested the addition of a new Transmission, Distribution, and Storage System Improvement Charge	Docket. No. 44910

					(TDSIC). For residential customers, this charge will be a fixed charge on top of the utility's monthly customer charge. The proposed TDSIC for 2018 is $1.19. This will increase annually until reaching $13.46 in 2024. Vectren currently has an $11.00 customer charge for residential customers. A settlement agreement filed in July 2017 reduces the proposed TDSIC charge to a maximum of $7.00, starting at $0.50 and increasing by $0.50 semi-annually. The Commission approved the settlement in September 2017.	
KY	Duke Energy Kentucky	$4.50	$11.22	*Pending*	In September 2017, Duke Energy Kentucky requested an increase in its residential monthly fixed charge.	Docket No. 2017-00321
	Kentucky Power	$11.00	$17.50	*Pending*	In June 2017, Kentucky Power requested an increase in its residential monthly fixed charge. A hearing was held in early October 2017.	Docket No. 2017-00179
MA	Eversource	$5.76 (avg.)	$8.00	*Pending*	In January 2017, Eversource requested an increase in its residential monthly fixed charge. As part of its general rate case, Eversource has proposed consolidating its distinct territories into Eastern and Western territories, whose rates will be aligned. Current residential fixed charges in each of Eversource's Massachusetts territories are as follows: $6.43 (Greater Boston - MetroWest); $6.87 (Cambridge); $3.73 (Plymouth, New Bedford, Cape Cod, Martha's	Docket No. 17-05

					Vineyard); and $6.00 (Western Massachusetts Electric Co.).	
MD	Delmarva Power & Light	$8.17	$9.08	*Pending*	In July 2017, Delmarva Power & Light requested an increase in its residential monthly fixed charge. Evidentiary hearings are scheduled for mid-December 2017.	Docket No. 9455
	PEPCO	$7.60	$8.81	*Pending*	In March 2017, PEPCO requested an increase in its residential monthly fixed charge.	Case No. 9443
MI	Alpena Power Co.	$5.00	$7.00	*Pending*	In June 2017, Alpena Power Company requested an increase in its residential monthly fixed charge. A hearing was scheduled for November 2017, but canceled in September 2017 while parties finalize a settlement agreement.	Docket No. 18324
	DTE Electric	$7.50	$9.00	*Pending*	In April 2017, DTE Electric requested an increase in its residential monthly fixed charge.	Docket No. 18255
	Indiana Michigan Power	$7.30	$18.00	*Pending*	In May 2017, Indiana Michigan Power requested an increase in its residential monthly fixed charge.	Docket No. 18370
MN	Minnesota Power	$8.00	$9.00	*Pending*	In November 2016, Minnesota Power requested an increase in its residential monthly fixed charge.	Docket No. 16-664
NC	Duke Energy Carolinas	$11.80	$18.51	*Pending*	In August 2017, Duke Energy Carolinas requested increasing its residential monthly fixed charge to $17.79. Duke also proposed a new Grid Modernization Rider, which includes a $0.72 fixed charge and a $0.00511/kWh variable charge for residential customers.	Docket E-7 Sub 1146

	Duke Energy Progress	$11.13	$19.50	*Pending*	In June 2017, Duke Energy Progress requested an increase in its residential monthly fixed charge.	[Docket E-2 Sub 1142]
NE	Lincoln Electric System	$19.50*	$26.50*	*Pending*	In September 2017, Lincoln Electric System (LES) proposed an increase in its residential monthly fixed charge and a decrease in variable energy rates. LES' fixed charge includes a $5.00 customer charge, plus a tiered facilities charge. A public meeting was held in early October, and the Administrative Board will consider the proposal on October 20th.	[LES Press Release] [Summary of Proposed Rates]
NJ	Atlantic City Electric Company	$4.44	$6.00	$5.00	In March 2017, Atlantic City Electric proposed an increase in its residential monthly fixed charge. In September 2017, the Board of Public Utilities approved a settlement agreement, which grants a portion of the utility's requested increase.	[Docket No. ER17030308] [Final Order]
NM	Public Service Company of New Mexico (PNM)	$7.00	$13.77	*Pending*	In December 2016, Public Service Company of New Mexico proposed an increase in its residential monthly fixed charge. A stipulation agreement was filed in May 2017, which would increase the customer charge to $7.64. A hearing was held in August 2017.	[Docket No. 16-00276-UT] [Stipulation]
	Southwestern Public Service Company d/b/a Xcel Energy	$8.50	$10.50	*Pending*	In November 2016, Southwestern Public Service Company (SPS) proposed an increase in its residential monthly fixed charge. In April 2017, the Commission found SPS' application to be incomplete and dismissed the application. The Commission directed SPS to file a new, complete	[Docket No. 16-00269-UT]

					application. The Commission denied a motion for rehearing in May, and SPS appealed the decision. The Supreme Court of New Mexico is currently considering the case.	
NV	Nevada Power d/b/a NV Energy	$12.75	$16.76	*Pending*	In September 2017, NV Energy requested an increase in its residential monthly fixed charge. Pursuant to A.B. 405, NV Energy's proposed tariff combines standard residential customers and residential net metering customers into a single class. While the requested fixed charge is an increase for standard residential customers, the proposed charge would be a decrease for existing net metering customers (current customer charge is $17.90).	Docket No. 17-06003
NY	Central Hudson Gas & Electric	$24.00	$27.00*	*Pending*	In July 2017, Central Hudson Gas & Electric requested an increase in its monthly residential fixed charge. The utility has proposed a $1.00 increase in its customer charge, as well as a new monthly service size charge. The service size charge is a monthly fixed charge based on annual kWh usage, and would range from $1.00 to $4.00.	Docket No. 17-01631
OH	Dayton Power & Light	$4.25	$13.73	*Pending*	In November 2015, Dayton Power & Light (DP&L) filed to increase fixed charges and reduce variable rates for a reported average monthly bill increase of $4.07. In March 2017, the Public Utilities Commission (PUC) of Ohio issued an RFP for an independent auditing firm to audit the application for a rate	Case No. 15-1830-EL-AIR "DP&L Seeks Electric Rate Increase"

					increase. The RFP includes a deadline of September 29, 2017 for the resulting audit report to be submitted. DP&L has agreed to not implement a rate increase while the audit is being conducted. In April 2017, the PUC selected a firm to conduct the audit.	
	Duke Energy Ohio	$6.00	$22.77	*Pending*	In March 2017, Duke Energy Ohio proposed an increase in its residential monthly fixed charge. The Public Staff filed a written report of its investigation of Duke Energy's proposal in September 2017 and recommended maintaining the customer charge of $6.00. A prehearing conference is scheduled for November 8th, and an evidentiary hearing is set to commence on December 11th.	Case No. 17-0032-EL-AIR
	Ohio Power Company d/b/a American Electric Power	$8.40	$18.40	*Pending*	American Electric Power proposed a two-phase increase for its residential fixed charge in May 2016. The proposed increase would begin at $13.40, then increase to $18.40 on January 1, 2018. In August 2017, Ohio Power filed a joint stipulation with a number of parties, which recommends maintaining the current customer charge until the utility files its next distribution rate case.	Case No. 13-2385-EL-SSO
OK	Empire District Electric Company	$12.50	$20.59	$12.50	In December 2016, Empire District Electric proposed an increase in its residential monthly fixed charge. In June 2017, the ALJ recommended that the rate increase be reduced. Due to Empire District Electric's recent acquisition, its proposed rates were rejected in August 2017.	Docket No. PUD 201600468 Order No. 667123

					The company's next rate case filing is to include at least 12 months of post-acquisition data.	
SC	Santee Cooper	$19.50	$25.00	$19.00	In June 2017, Santee Cooper proposed a rate increase, including an increase in its residential monthly fixed charge. Under Santee Cooper's proposal, the charge would increase to $22.50 in 2018 and $25.00 in 2019. Public meetings were scheduled for August 2017; however, Santee Cooper's Board of Directors voted to suspend the rate adjustment activities in August 2017. The bankruptcy of Westinghouse led to the suspension of construction on the V.C. Summer nuclear plant, in which Santee Cooper had a financial interest. The escalating costs of the project had led Santee Cooper to propose new rates, but the suspension of the project makes the rate adjustment unnecessary.	Proposed Rates Santee Cooper Website
TX	El Paso Electric	$6.90	$10.85	*Pending*	In February 2017, El Paso Electric proposed an increase in its residential monthly fixed charge. Settlement terms on the major issues of the case were reached in September 2017, but a settlement agreement had not yet been filed as of the end of Q3 2017.	Docket No. 46831
	Oncor	$3.06	$6.64	*Pending*	In March 2017, Oncor proposed an increase in its residential monthly fixed charge. Oncor also proposed a separate rate class for DG customers with a minimum bill. A settlement agreement was filed in August 2017, which	Docket No. 46957

					includes a fixed charge increase of $3.49. A proposed order was filed in September 2017, which would approve the settlement.	
	Sharyland Utilities	$6.74	$10.00	*Dismissed*	In April 2016, Sharyland Utilities requested an increase in its residential monthly fixed charge for customers in its McAllen division, but not its SBC division. The rate case was dismissed in September 2017, due to Sharyland's sale of its retail operations to Oncor. Oncor rates are now applicable to former Sharyland customers.	Docket No. 45414
VA	Old Dominion Power Company d/b/a Kentucky Utilities	$12.00	$16.00	*Pending*	In September 2017, Old Dominion Power Company, a subsidiary of Kentucky Utilities, requested an increase in its residential monthly fixed charge.	Docket No. PUR-2017-00106
	Rappa-hannock Electric Cooperative	$10.00	$20.00	*Pending*	In May 2017, Rappahannock Electric Cooperative requested an increase in its residential monthly fixed charge.	Docket No. PUR-2017-00044
WA	Avista Utilities	$8.50	$10.00	*Pending*	In May 2017, Avista Utilities requested an increase in its residential monthly fixed charge. A public comment hearing is scheduled for November 2017.	Docket No. UE-170485
	Puget Sound Energy	$7.49	$9.00	*Pending*	In January 2017, Puget Sound Energy requested an increase in its residential monthly fixed charge. In September 2017, Puget Sound Energy filed a multi-party partial settlement agreement. The settlement covers a number of issues, but does not address the proposed fixed charge increase.	Docket No. UE-170033

WI	Northern States Power Company d/b/a Xcel Energy	$14.00	$17.00	*Pending*	In May 2017, Xcel Energy requested an increase in its residential monthly fixed charge. Initial briefs are due by October 19th.	[Docket No. 4220-UR-123]()
	Superior Water, Light, & Power	$7.00	$9.00	$9.00	In June 2016, Superior Water, Light, and Power (SWLP) proposed a residential rate increase. SWLP filed its proposed rate design in August 2016, which includes an increase in the residential monthly fixed charge. In August 2017, the Public Service Commission approved the full requested increase.	[Docket No. 5820-UR-114]()

* Denotes that the utility uses a daily fixed charge for residential customers instead of a monthly fixed charge. All daily charges are converted into monthly charges for this table using the following formula: [(365 days/year)*($[fixed charge]/day)]/(12 months/year) = $[fixed charge]/month. If the charge varies by kWh consumption, it is assumed that the customer uses 900 kWh.

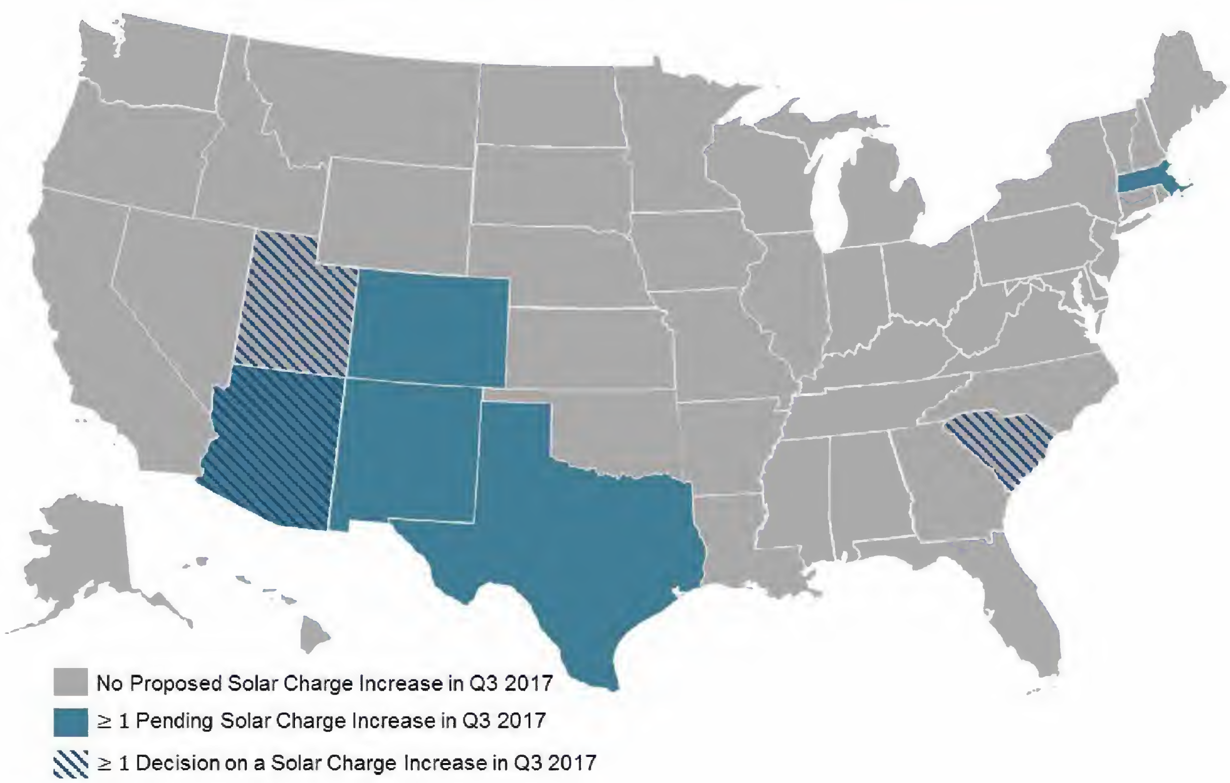
DEMAND AND SOLAR CHARGES

Key Takeaways:

- In Q3 2017, there were 14 pending or recently decided proposals from 10 utilities in 7 states to adopt residential demand charges or other charges on residential solar customers.
- Of these proposals, five were requests to add traditional demand charges, three were requests to add an additional fixed fee for solar customers, two were demand-based minimum bills, two were requests to add DG capacity-based charges, and two were requests to increase existing residential DG standby charges.
- Settlement agreements that exclude additional mandatory charges for DG customers were approved in Arizona and Utah.

In Q3 2017, there were 14 utility proposals pending or decided in 7 states to adopt extra charges on residential solar customers or demand charges on all residential customers. Only four utilities have proposed new charges for distributed generation (DG) customers so far this year.

Figure 10. Proposed Demand or Solar Customer Charges (Q3 2017)

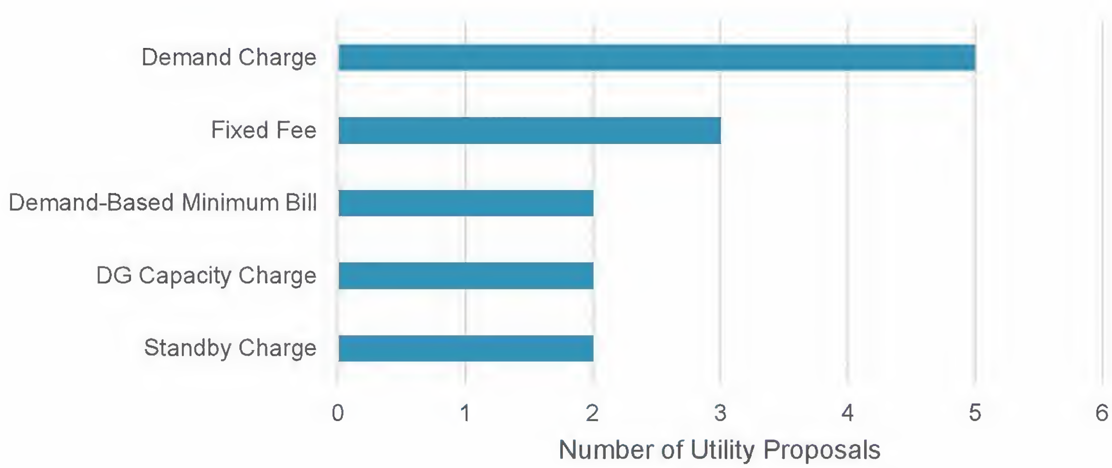


Residential demand charge proposals continued to struggle finding success in Q3 2017. Settlement agreements excluding originally-proposed demand charges for residential DG customers were approved in both Arizona and Utah. Arizona Public Service had originally

proposed a mandatory demand charge ranging from $11.50 to $16.40 per kW, depending upon the season, but the approved settlement includes only a voluntary demand tariffs, with three designs to select from. DG customers may also select a non-demand tariff with time-varying rates and a charge based on the DG system capacity. In Utah, Rocky Mountain Power had proposed a demand charge of $9.02 per kW, but the approved settlement does not separate DG customers into a separate customer class and only impacts net metering credit rates at this time.

Two pending settlements in Texas also exclude residential demand charges that were initially proposed. In lieu of a demand charge and additional fixed fee, El Paso Electric and other stakeholders have agreed to a $30.00 minimum bill. A proposed settlement in Oncor's rate case also excludes the demand-based minimum bill originally requested. No state public utilities commission has approved a demand charge on residential solar customers since the beginning of 2015.‡

Figure 11. Solar Charges Pending or Decided in Q3 2017



Very little activity has occurred on residential demand and other solar charges so far during 2017. Only four utilities – Eversource – MA (Jan. 2017), El Paso Electric – TX (Feb. 2017), Oncor – TX (Mar. 2017), and Black Hills Energy – CO (Jul. 2017) – have proposed new charges for distributed solar customers so far this year.

However, other regulatory actions being taken may lead to new charges being proposed for distributed solar customers. In Idaho and Iowa, utilities recently requested to separate residential DG customers into a unique customer class without making any changes to rates at this time. In Kansas, regulators determined that it is appropriate to separate DG customers into a separate rate class, which could include demand charges or DG-capacity based charges; however, any specific tariff changes will take place in utility-specific filings. NV Energy in

‡ The 50 States of Solar began consistently tracking demand charges on residential solar customers in January 2015.

Nevada proposed a study of the need for demand charges, but this request was denied by the Commission.

Box 5. Demand Charges, Standby Charges, & Grid Access Fees

A **demand charge** is a charge that varies based on a customer's maximum rate of energy consumption, or demand, during a billing period. A customer's demand is measured in kilowatts (kW), and is typically calculated based on the average rate of energy consumption over a 15, 30, or 60 minute interval. The charge is then based on the interval with the highest average demand. In certain cases, only a customer's highest demand during the utility's system peak periods is used in calculating a demand charge, also known as "**coincident peak demand**." Most often, demand charges are based on a customer's "**non-coincident peak demand**", which may occur at any time during the billing period, regardless of when they utility's system peak occurs. Demand charges are common for commercial and industrial customers, and though rare for residential customers, are most often paired with time-of-use rate schedules when included in residential rates. A **standby charge** is a charge applied to customers with on-site generation, and may have volumetric, demand-based, and capacity-based components. Standby charges are intended to compensate the utility for providing power when the on-site generator is not producing energy. Another type of solar charge is a **flat monthly fee**, sometimes called a **grid access charge**, which functions as a higher total fixed charge.

Recent legislative action could also lead to new charges for distributed solar customers. Net metering legislation enacted in Montana this session allows the Commission to approve a separate customer class for customer-generators within utility general rate cases if the pending net metering cost-benefit analysis supports this. Similarly, legislation enacted in North Carolina requires net metering customers to pay their full cost of service, and specifically notes that demand charges may be utilized.

Table 9. Updates on Residential Demand and Solar Charges (Q3 2017)

State	Utility	Monthly Demand/Solar Charge(s)			Description	Source
		Current	Proposed	Approved		
AZ	Arizona Public Service	$0.00	$11.50-$16.40 per kW (varies seasonally), based on the max 60-min. demand during peak hours	$0.93 per kW capacity OR $8.40 per kW (based on the max 60-min. demand during peak hours) OR $12.239 per kW (summer)/ $17.438 per kW (winter) OR R-TECH demand charge (described to right)	As part of its general rate case filed in June 2016, Arizona Public Service proposed three new residential rate options, each with a mandatory demand charge of either $6.60/kW, $8.40/kW, or $11.50-$16.40/kW (varies seasonally) for all residential customers. Solar customers must take service on the third rate option with a demand charge of $11.50-$16.40/kW. A settlement agreement among 30 parties, including major solar advocacy groups, was filed in March 2017. The agreement includes four rate options for residential DG customers: three options (R-2, R-3, and pilot rate R-TECH) include a demand charge, and one option (TOU-E) does not. The TOU-E schedule does, however, include a charge of $0.93 per kW of DG capacity. Proposed schedule R-2 includes a demand charge of $8.40/kW, and schedule R-3 includes a demand charge of $17.438/kW during the summer and $12.239/kW during the winter. Schedule R-TECH includes two demand charges: an on-peak demand charge of $20.25/kW during the summer and $14.25/kW during the winter, and an off-peak demand charge of $6.50/kW for demand over 5 kW. Demand measurements are based on the customer's highest	Docket No. E-01345A-16-0036 Settlement Agreement Proposed Tariffs Decision No. 76295

				60-minute demand during on-peak hours (3 pm to 8 pm Monday through Friday) over the billing period. The off-peak demand charge in schedule R-TECH is the exception to this and based on demand during any hour not categorized as on-peak. In May, the ACC staff filed a brief concluding that the settlement should be adopted. The ACC approved the agreement in August 2017.	
Tucson Electric Power	$0.00	$8.85 per kW from 0-5 kW; $12.85 per kW for over 5 kW, based on the 60-min. non-coincident max demand during the billing cycle	*Pending*	As part of its general rate case filed in November 2015, Tucson Electric Power (TEP) proposed a mandatory new rate design for "partial requirements customers," including new users of solar. The proposed rate has a three-part structure including a monthly service charge, a demand charge, and volumetric energy charges. This rate would be optional for standard residential customers. In a February decision, the Arizona Corporation Commission approved new voluntary demand rates for residential customers. TEP is currently proposing two rate options for residential DG customers; both include time-of-use rates, while one includes a capacity-based "grid access charge" and the other includes a demand charge. The proposed demand charge has been adjusted since TEP's original filing. The tariff also includes a monthly fixed meter charge of $4.32. A hearing on Phase 2 issues, including DG rate design issues, is scheduled for October 23rd.	[Docket No. E-01933A-15-0322]

Tucson Electric Power	$0.00	$2.50 per kW-DC, based on DG system size	*Pending*	Tucson Electric Power has proposed two rate options for residential DG customers, both including time-of-use rates. One tariff includes a "grid access charge" based on the capacity of the customer's DG system, while the other tariff includes a demand charge. Both tariffs also include a monthly fixed meter charge of $4.32. A hearing on Phase 2 issues, including DG rate design issues, is scheduled for October 23rd.	Docket No. E-01933A-15-0322
UniSource Energy Services (UNS Electric)	$0.00	$5.50 per kW from 0-5 kW; $7.75 per kW for over 5 kW, based on the 60-min. non-coincident max demand during the billing cycle	*Pending*	As part of its general rate case filed in May 2015, UniSource Energy Services (UNS) proposed a mandatory new rate design for “partial requirements customers,” including new users of solar. The proposed rate has a three-part structure including a monthly service charge, a demand charge, and volumetric energy charges. This rate would be optional for standard residential customers. The Arizona Corporation Commission issued a decision in the rate case in August 2016, but left the net metering and DG customer rate design portions of the docket open in order to utilize the filings and conclusions in the Value of DG docket (Docket No. E-00000J-14-0023). A decision was made in the Value of DG proceeding in December 2016. UNS has since adjusted its proposed tariffs for residential DG customers, proposing two time-of-use rate options, one with a demand charge and the other with a capacity-based charge. Both tariffs also include a	Docket No. E-04204A-15-0142

					monthly fixed meter charge of $3.92. A hearing on Phase 2 issues, including these DG rate design issues, is scheduled for October 23rd.	
	UniSource Energy Services (UNS Electric)	$0.00	$1.00 per kW-DC, based on DG system size	*Pending*	Unisource Energy Services has proposed two rate options for residential DG customers, both including time-of-use rates. One tariff includes a "grid access charge" based on the capacity of the customer's DG system, while the other tariff includes a demand charge. Both tariffs also include a monthly fixed meter charge of $3.92. A hearing on Phase 2 issues, including DG rate design issues, is scheduled for October 23rd.	[Docket No. E-04204A-15-0142]()
CO	Black Hills Energy	$16.50	$25.45	*Pending*	In July 2017, Black Hills Energy proposed an increase in the monthly fixed charge for residential net metering customers. While the utility proposed an increase to $20.13 for standard residential customers, the charge for residential net metering customers would be $25.45. The company noted that this $5.32 difference is primarily related to the cost of the production meters used. The utility has also proposed higher per-kWh energy rates for its residential net metering sub-class than what is being proposed for the standard residential class. This rate would be a year-round, single-tier rate rather than the year-round inclining block rate proposed for standard residential customers.	[Docket No. 17AL-0477E]()

MA	Eversource	$0.00	Eastern MA: $10.88 + $2.26 per kW, based on the 15-min. non-coincident max demand during the billing cycle	*Pending*	As part of its general rate case filed in January 2017, Eversource proposed a new Minimum Monthly Reliability Charge (MMRC) for net metering customers installing systems after January 1, 2018. The proposed MMRC is a combination of a higher fixed charge and a demand charge, based on customers' non-coincident peak demand. The MMRC is included as a part of the standard residential service tariff, but is only applicable to new net metering customers. The utility will install demand meters for new residential net metering customers. The Attorney General proposed bifurcating the revenue requirement and rate design portions of the case, addressing the rate design issues in a second phase; however, the Department of Public Utilities denied this request. In June 2017, Everource proposed an alternative rate design, whereby both Eastern and Western Massachusetts customers would have the same rates. In Eversource's original filing, Eastern MA customers would have had an MMRC of $10.38 + $2.12 per kW, while Western MA customers would have had an MMRC of $14.55 + $2.31 per kW.	Docket No. 17-05
NM	Southwestern Public Service Company d/b/a Xcel Energy	$0.0367 per kWh prod-uced	$0.0533 per kWh produced	Dismissed	In November 2016, Southwestern Public Service Company (SPS) proposed an increase in its residential DG production standby charge from $0.005 to $0.007 and an increase in its residential	Docket No. 16-00269-UT

					DG transmission and distribution standby charge from $0.031 to $0.046. The standby rates are based on the amount of per kWh production from the customer generation system that is either used on-site or applied as an offset to energy delivered from SPS. In April 2017, the Commission found SPS' application to be incomplete and dismissed the application. The Commission directed SPS to file a new, complete application. The Commission denied a motion for rehearing in May, and SPS appealed the decision. The Supreme Court of New Mexico is currently considering the case.	
SC	Santee Cooper	$4.40 per kW installed capacity	$4.70 per kW installed capacity	$4.40 per kW installed capacity	In June 2017, Santee Cooper proposed a rate increase, including an increase in its residential DG customer standby charge. Under Santee Cooper's proposal, the rate would increase from $4.40 per kW of installed capacity to $4.60 in 2018 and $4.70 in 2019. The proposal also includes an increase in the commercial DG customer standby charge. Public meetings were scheduled for August 2017; however, Santee Cooper's Board of Directors voted to suspend the rate adjustment activities in August 2017. The bankruptcy of Westinghouse led to the suspension of construction on the V.C. Summer nuclear plant, in which Santee Cooper had a financial interest. The escalating costs of the project had led Santee	Proposed Rates Santee Cooper Website

					Cooper to propose new rates, but the suspension of the project makes the rate adjustment unnecessary.	
TX	El Paso Electric	$0.00	$6.20 per kW	*Pending*	In February 2017, El Paso Electric filed a rate case including a new customer class for residential DG customers, which would add a demand charge and new TOU rates for these customers. While a complete settlement has not yet been filed, as of the end of Q3 2017, the demand and fixed charges have been replaced by a $30.00 minimum bill in settlement negotiations.	Docket No. 46831 El Paso Electric Release
	El Paso Electric	$6.90	$18.15	*Pending*	In February 2017, El Paso Electric filed a rate case including a new customer class for residential DG customers. The proposed tariff includes a demand charge, TOU rates, and a higher fixed customer charge than the standard residential tariff. While a complete settlement has not yet been filed, as of the end of Q3 2017, the demand and fixed charges have been replaced by a $30.00 minimum bill in settlement negotiations.	Docket No. 46831 El Paso Electric Release
	Oncor	$0.00	$3.53 per kW minimum bill, based on the non-coincident max demand during the billing cycle	*Pending*	In March 2017, Oncor filed a rate case including a demand charge for DG customers. The demand charge would function as a minimum bill, being charged only to the extent that the customer's normal bill falls below the demand charge. A settlement agreement filed in August 2017 drops the proposed demand-based minimum bill. The Commission issued a proposed order adopting	Docket No. 46957 Settlement Agreement Proposed Order

					the settlement in September 2017.	
UT	Rocky Mountain Power	$6.00	$15.00	$6.00	In November 2016, Rocky Mountain Power (RMP) proposed a new tariff for net metering customers seeking interconnection after December 9, 2016. Customers taking service on this tariff would have a $15.00 monthly fixed charge, as opposed to the $6.00 fixed charge for other RMP residential customers. In December 2016, the proposal was suspended to allow stakeholders to continue to seek mutually acceptable resolutions. Parties filed a settlement agreement in August 2017, which was approved in September. The settlement does not separate DG customers into their own customer class and does not include a demand charge or increased fixed charge.	Docket No. 14-035-114 Docket No. 16-035-T14 Settlement Agreement Order Approving Settlement Stipulation
	Rocky Mountain Power	$0.00	$9.02 per kW, based on the 60-min. max demand during specified on-peak hours	$0.00	In November 2016, Rocky Mountain Power (RMP) proposed a new tariff for net metering customers seeking interconnection after December 9, 2016. The proposed tariff includes a demand charge, based on a customer's maximum demand during specified on-peak hours (8am to 10am Mon-Fri for October through April, and 3pm to 8pm Mon-Fri for May through September). In December 2016, the proposal was suspended to allow stakeholders to continue to seek mutually acceptable resolutions. Parties filed a settlement agreement in August 2017, which was approved in September. The settlement	Docket No. 14-035-114 Docket No. 16-035-T14 Settlement Agreement Order Approving Settlement Stipulation

				does not separate DG customers into their own customer class and does not include a demand charge or increased fixed charge.	

THIRD-PARTY SOLAR OWNERSHIP

Key Takeaways:

- In Q3 2017, one state took action regarding the legality of third-party ownership options.
- The North Carolina Court of Appeals upheld the Utilities Commission's ruling that NC WARN's third-party PPA is illegal.
- As most states have concluded their 2017 legislative sessions, little action related to third-party ownership occurred during Q3 2017.

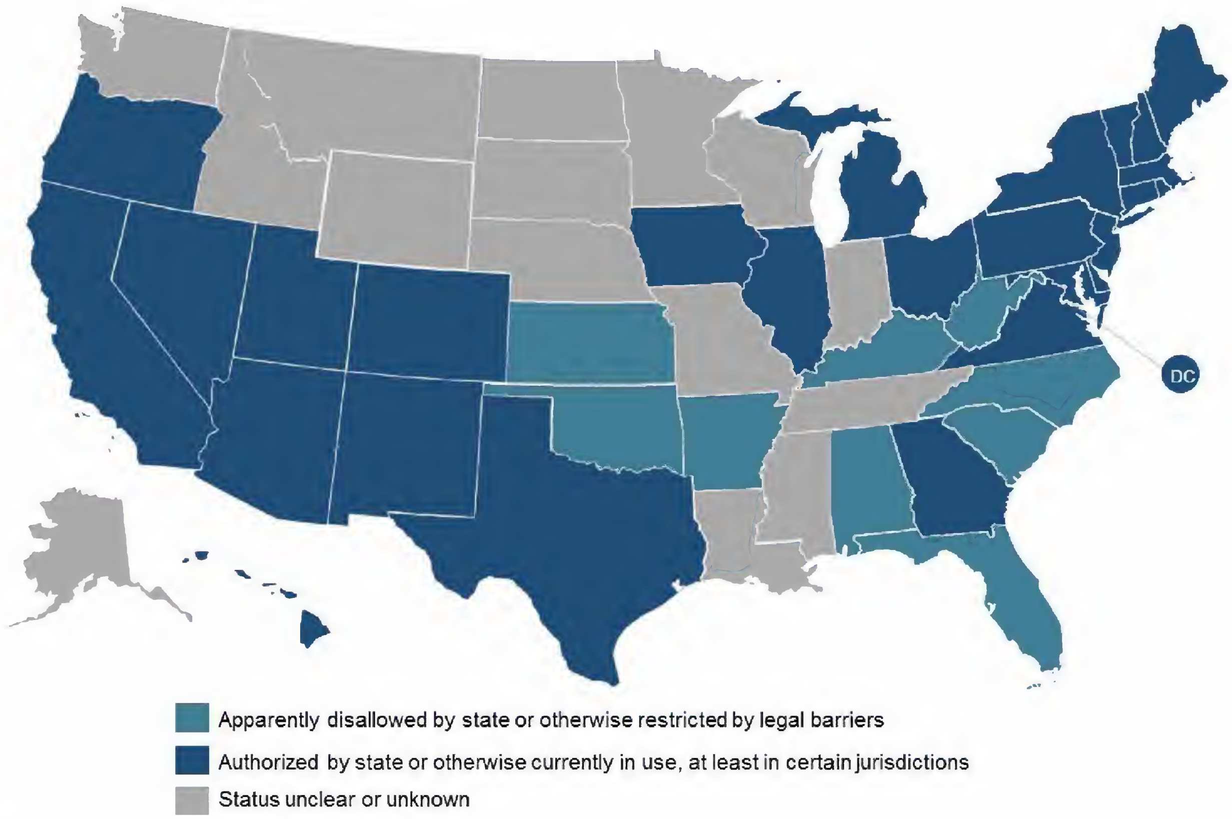
Just one state – North Carolina – took action related to the legality of third-party solar ownership in Q3 2017. As most legal barriers to third-party power purchase agreements are statutory, legislative action is often required to remove these. As such, action related to third-party ownership is likely to increase as states begin their 2018 legislative sessions.

Figure 12. Action on Solar Third-Party Ownership (Q3 2017)

In North Carolina, Governor Cooper signed H.B. 589 into law in late July, legalizing solar leasing in the state. Unlike most states, the total solar capacity that may participate in the leasing program is capped at 1% of Duke Energy's previous 5-year average coincident peak demand (South Carolina is the only other state to limit solar leasing capacity). However, North Carolina does not have an aggregate capacity limit on net metering, as several states do. Leasing will

only be available in Duke Energy's service territory, as well as any municipal utilities that opt to offer solar leases.

Figure 13. Third-Party Solar PPA Legality



Source: NC Clean Energy Technology Center [13]

While H.B. 589 makes solar leasing available in North Carolina, third-party power purchase agreements (PPA) remain illegal. A local non-profit's test case and request for a declaratory ruling sought a determination by the Utilities Commission that third-party PPAS – at least to non-profit entities – are legal. However, the Commission ruled against the non-profit in April 2016, and the state Court of Appeals upheld this decision in September 2017. The non-profit has indicated that it may further appeal the decision to the state Supreme Court.

Table 10. Solar Third-Party Ownership Updates (Q3 2017)

State	Description	Eligible Sector(s)	Source
NC	In June 2015, nonprofit organization NC WARN submitted a request for a declaratory ruling to the NC Utilities Commission regarding the organization's power purchase agreement with a church located in the state. North Carolina statutes generally define an entity selling electricity as a "public utility." In April 2016, the Commission issued a declaratory ruling clearly indicating that third-party sales are prohibited in North Carolina. NC WARN appealed the decision, and in December 2016 the Public Staff and the utilities filed briefs supporting the Commission's declaratory ruling. The North Carolina Court of Appeals upheld the Commission's ruling in September 2017. NC WARN has indicated that it is considering an appeal to the North Carolina Supreme Court.	Non-Profit Entities	Docket No. SP-100 Sub 31 No. COA 16-811 NC WARN Statement
	The North Carolina legislature passed H.B. 589 in June 2017, which authorizes and establishes rules for solar leasing in the state. Utilities with at least 150,000 customers (Duke Energy Carolinas and Duke Energy Progress) must offer solar leasing; municipal utilities may voluntarily offer leasing. The bill includes detailed requirements for disclosures, record keeping, and other issues related to solar leases. The total installed capacity limit for leased solar systems is 1% of the utility's previous 5-year average coincident peak demand. The Governor signed H.B. 589 into law in July 2017.	Residential, Commercial	H.B. 589

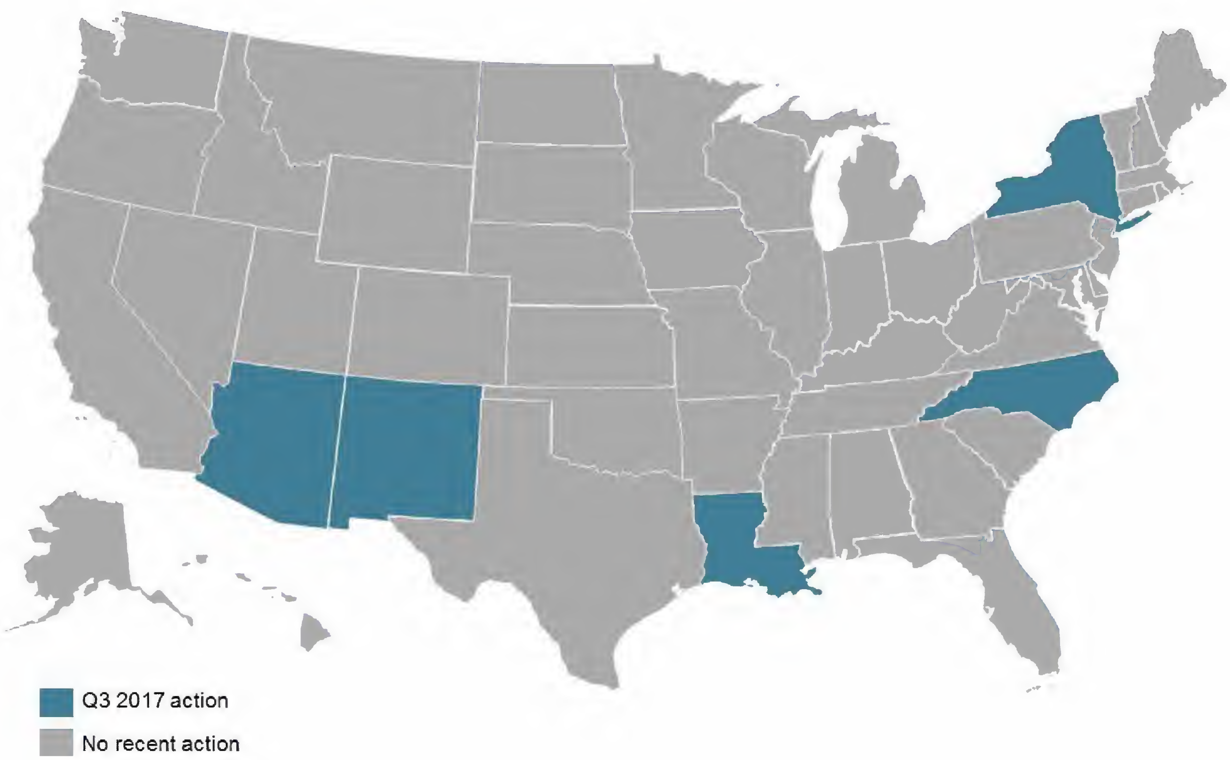
UTILITY-LED ROOFTOP SOLAR PROGRAMS

Key Takeaways:

- Utilities in five states took action on utility-led rooftop solar programs during Q3 2017.
- Arizona Public Service and Duke Energy (North Carolina) gained approval to offer utility-owned rooftop solar systems to their customers during Q3 2017.
- The New York Public Service Commission denied a request for rehearing of its 2015 decision regarding utility ownership of DERs.

Utility-led rooftop solar programs are an emerging area of interest, yet few utilities have proposed or implemented such programs to date. However, two utilities – Arizona Public Service and Duke Energy (North Carolina) – gained approval for such programs in Q3 2017.

Figure 14: Utility-Led Rooftop Solar Program Updates (Q3 2017)



In Arizona, the Corporation Commission approved a settlement agreement, which includes a new utility-owned rooftop solar program. The Governor of North Carolina signed a bill in July 2017, which allows the state's major utility – Duke Energy – to offer solar leases directly to customers. Municipal utilities may voluntarily opt in to offer solar leases to their customers. New York took a different direction, with the Public Service Commission denying a request for rehearing of a March 2015 decision that disallows utilities from owning DERs, unless the market fails to deliver DERs in a cost-effective manner.

Table 11. Updates on Utility-Led Rooftop Solar Programs and Policies (Q3 2017)

State	Utility	Description	Source
AZ	Arizona Public Service	As part of Arizona Public Service's (APS) general rate case, a settlement agreement was filed in March 2017 and later approved by the Arizona Corporation Commission in August 2017. As part of the settlement, APS will begin a new utility-owned distributed solar program called AZ Sun II, which will be focused on providing rooftop solar to low and moderate income customers. APS will select third-party solar contractors to install the systems through an RFP process and recover its costs through the Renewable Energy Adjustment Clause. The settlement notes that APS may request that capital costs associated with the projects be included in its rate base; capital costs are limited to between \$10 million and \$15 million per year.	Docket No. E-01345A-16-0036 Settlement Agreement Decision No. 76295
LA	Entergy New Orleans	Energy New Orleans recently performed a market test for a self-build aggregated rooftop solar project. The self-build project would consist of multiple PV systems located on customer rooftops, and the electricity would be fed into the distribution grid. The project was bid into Entergy New Orleans' 20 MW renewables RFP. Entergy New Orleans announced in May 2017 that it had placed three proposals, totaling 45 MW, on the Primary Selection list. One of the three proposals selected is the self-build project. In early October 2017, Entergy filed an application with the City Council for approval to construct the projects.	Entergy New Orleans Press Release RFP Announce-ment
NC	Duke Energy Carolinas, Duke Energy Progress, Municipal Utilities	The North Carolina Legislature passed H.B. 589 in June 2017, which authorizes and establishes rules for solar leasing. The bill includes detailed requirements for disclosures, record keeping and other issues related to solar leases. The bill also allows utilities serving more than 150,000 to offer solar leases to their customers, as well as municipal utilities opting into the program. The Governor signed H.B. 589 into law in July 2017.	H.B. 589
NM	El Paso Electric	In November 2015, the New Mexico Public Regulation Commission commenced an inquiry into the desirability of utility-owned distributed generation facilities that serve specific retail customers. The inquiry was motivated by the recent approval by the Commission of a proposal by El Paso Electric to build a distributed generation facility on, and supply electricity for, Holloman Air Force Base. Generally utilities have not been allowed to undertake these projects due to concerns that they would advantage particular customers, and possibly lead to costs being passed to customers who gain no benefit from the projects. In January 2017, the Commission requested additional information from El Paso Electric, Clean Energy Collective, and Kit Carson Electric Cooperative.	Docket No. 15-00355-UT

NY	All Utilities	In March 2015, petitioners filed a request for rehearing on the Public Service Commission's (PSC) order adopting a regulatory policy framework and implementation plan to clarify 1) utility ownership of DERs for low to moderate income customers and 2) opportunities for participation by the public in the Reforming the Energy Vision proceeding. The previous PSC order did not allow utility ownership of DERs, with an exception that it could be allowed if the market failed to deliver in a cost-effective manner. In August 2017, the PSC issued an order denying the petitioners' request for rehearing on the issue.	Docket No. 14-00581/14-M-0101

Q4 2017 OUTLOOK

While not a state policy decision, the Section 201 trade petition filed by Suniva and SolarWorld will remain a key policy issue for distributed solar in Q4 2017. In September 2017, the International Trade Commission found injury in the trade case, and held a hearing on a potential remedy on October 3rd.[14] The Commission will recommend a remedy to President Trump on November 13th, at which point the President will have 60 days to make a decision on a remedy.[15]

At the state level, legislative activity will begin to pick up again in Q4 2017, as legislators pre-file bills in several states. In early Q4 2017, a hearing was held on several proposed net metering bills in **Massachusetts**. Bills related to net metering and distributed solar also remain pending in **New Jersey** and **New York**, where state legislatures are still in session.

Each of **New Hampshire**'s four working groups formed as a result of the June 2017 net metering successor tariff order will meet during Q4 2017. Work toward a net metering successor tariff will also continue in **Utah**, where an export credit rate proceeding will be initiated. A recent decision in **Kansas**' value of solar docket is likely to lead to new rate proposals for DG customers in the state.

A decision is expected in Q4 2017 from the **Hawaii** Public Utilities Commission regarding changes to utilities' DG compensation tariffs. **Maryland**'s value of solar study is targeted for completion in December 2017, and implementation of **North Carolina**'s H.B. 589 will continue during Q4 2017.

A hearing on DG rate design issues for Tucson Electric Power and UNS Electric in **Arizona** is scheduled for Q4 2017, and a decision in Interstate Power & Light's ongoing rate case in **Iowa** is expected during Q4 2017. In **Texas**, settlement negotiations are expected to conclude in El Paso Electric's rate case during Q4 2017, and a settlement is pending approval in Oncor's rate case.

In early Q4 2017, Emera **Maine** filed its application for a rate increase, proposing a minimum bill increase of approximately 10.8% for the Maine Public District and a minimum bill increase of 9.5% for the Bangor Hydro District. Thirty-six requests to increase residential fixed charges or minimum bills were pending at the end of Q3 2017, as well as five requests to adopt demand charges for DG customers.

Looking further ahead, net metering cost-benefit studies are expected to be completed in **Montana** in April 2018 and in **Michigan** in June 2018. **Oregon** utilities will make their Resource Value of Solar filings by July 2018, and the **Missouri** Public Service Commission staff will submit its report on distributed energy resources by March 2018.

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